Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

February 10, 2009

Thompson River Power, LLC
Scott Magie
701 E. Lake St., Suite 300
Wayzata, MN 55391

Dear Mr. Magie:

Air Quality Permit #3175-06 is deemed final as of February 10, 2009, by the Department of Environmental Quality (Department). This is a permit modification for Thompson River Power's existing facility pursuant to the Order issued by the Board in the matter of contested case number BER 2006-18 AQ. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Vickie Walsh

Jenny O'Mara

Vickie Walsh
Air Permitting Program Supervisor
Air Resources Management Bureau
(406) 444-9741

Jenny O'Mara
Environmental Engineer
Air Resources Management Bureau
(406) 444-1452

VW:JO
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

# Air Quality Permit #3175-06

Thompson River Power, LLC
701 E. Lake St., Suite 300
Wayzata, MN 55391

February 10, 2009

AIR QUALITY PERMIT

Issued To: Thompson River Power, LLC
701 E. Lake St., Suite 300
Wayzata, MN 55391

Permit: #3175-06
Application Complete: 11/10/08
Preliminary Determination Issued: 12/19/08
Department Decision Issued: 1/23/09
Permit Final: 2/10/09
AFS: #089-0009

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Thompson River Power, LLC (TRP), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location

TRP operates a 16.5-megawatt (MW) capacity electricity and steam co-generation plant. A complete list of permitted equipment and emission sources are contained in Section I.A of the permit analysis. TRP's plant is located approximately 3.7 miles east-southeast of Thompson Falls, Montana. The legal description of the site is in the SW¼ of the NW¼ of the NE¼ of Section 13, Township 21 North, Range 29 West, in Sanders County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 11, Easting 631.6 kilometers (km), and Northing 5270.6 km.

B. Current Permit Action

On April 22, 2008, the Board of Environmental Review (Board) remanded MAQP #3175-04 to the Department to conduct a thorough, top-down supplemental Best Available Control Technology (BACT) analysis for periods of non-steady state operation. The current permit action is a modification to MAQP #3175-04 pursuant to the Order issued by the Board in the matter of contested case number BER 2006-18 AQ. The modification establishes permit limitations, conditions and reporting requirements in accordance with the results of the startup, shutdown and ash-pulling periods top-down BACT determination submitted by TRP on May 30$^{th}$ with additional information received on July 29$^{th}$, August 21$^{st}$, September 3$^{rd}$, October 2$^{nd}$, October 21$^{st}$, and October 29$^{th}$ and November 10$^{th}$ pursuant to the Board order.

Pursuant to this request, TRP requested the following changes to the permit terms/conditions relating to Startup and Shutdown Events and Ash-Pulling Periods. In addition to the requested permit modification, the current permit action also includes revisions to assure compliance during non-steady state operations and ash-pulling periods.

- Incorporation of *Best Management Operational Practices for Startup and Shutdown Events*;
- Evaluation of BACT specifically for Startup and Shutdown Events;
- Evaluation of BACT specifically for Ash-Pulling Periods;
- Establishment of a federally enforceable boiler heat sulfur limit;
- Establishment of $NO_x$ and $SO_2$ limits for Startup and Shutdown Events and Ash-Pulling Periods;
- Inclusion of a "monitoring period" to establish $NO_x$ and $SO_2$ emission limits, and/or to verify existing steady-state limits during Ash-Pulling Periods; and
- Incorporation of *Best Management Operating Procedures for Ash-Pulling Periods.*

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. TRP shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, and not subject to 40 CFR Part 60, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

2. TRP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (PM) (ARM 17.8.308).

3. TRP shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation (ARM 17.8.749).

4. TRP shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart A, and 40 CFR 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart A and Subpart Db).

5. TRP shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The coal analysis shall contain, at a minimum, sulfur content (sulfur percent (by weight) and in pounds of sulfur per million British thermal units, lb S/MMBtu), ash content, heating value (Btu/lb), and chlorine concentration (ARM 17.8.749 and ARM 17.8.752).

6. TRP shall install and operate a Continuous Opacity Monitoring System (COMS) to monitor compliance with the boiler opacity limits (ARM 17.8.340 and 40 CFR 60, Subpart Db).

7. TRP shall install and operate an oxides of nitrogen ($NO_x$) Continuous Emission Monitoring System (CEMS) to monitor compliance with the boiler $NO_x$ emission limits. The applicable NOx CEMS shall be installed and certified within 180 days of initial boiler startup following issuance of Permit #3175-06 (ARM 17.8.340 and 40 CFR 60, Subpart Db).

8. TRP shall install and operate a sulfur dioxide ($SO_2$) CEMS to monitor compliance with the boiler $SO_2$ emission limits. The applicable $SO_2$ CEMS shall be installed and certified within 180 days of initial boiler startup following issuance of Permit #3175-06 (ARM 17.8.749).

9. At all times, including periods of startup, shutdown, ash-pulling, soot blowing and malfunction, TRP shall, to the extent practicable, maintain and operate any affected equipment including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions (ARM 17.8.749 and ARM 17.8.752).

B. Boiler Startup and Shutdown Operations

1. Boiler heat input capacity shall be limited to 192.8 million British thermal units per hour (MMBtu/hr) during startup and shutdown operations based on a 1-hour average (ARM 17.8.749).

2. The requirements contained in Section II.B shall apply during boiler startup and shutdown operations. Boiler startup and shutdown events shall be conducted as described in the *Boiler Startup and Shutdown Procedures* included in Attachment 3 of Permit #3175-06 and *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department; or according to another startup and shutdown plan as may be approved by the Department, in writing (ARM 17.8.749 and ARM 17.8.752).

3. Boiler startup operations, as described in the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department, and generally described in Attachment 3 of Permit #3175-06, shall not exceed 48 hours from initial fuel feed to the boiler pre-heater or boiler, whichever is applicable at initiation of the boiler startup event (ARM 17.8.752).

4. Boiler shutdown operations, as described in Attachment 3, shall not exceed 8 hours from initial backing down of solid fuel feed (coal and/or wood-waste) to the boiler (ARM 17.8.752).

5. During boiler startup and shutdown operations, the boiler may combust wood-waste/biomass, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, or propane (ARM 17.8.752).

6. The boiler baghouse (DC5) shall be operational during startup and shutdown event(s). Other pollution control equipment shall be operated as described in the *Best Management Operational Practices for Startup and Shutdown Events* and as summarized in Attachment 3 of Permit #3175-06 (ARM 17.8.749).

7. During startup and shutdown events, $NO_x$ emissions from the boiler stack shall not exceed 74.0 lb/hr (ARM 17.8.752).

8. During startup and shutdown events, $SO_2$ emissions from the boiler stack shall not exceed 155.0 lb/hr (ARM 17.8.752).

9. In the event that the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department, are modified significantly, such that boiler emissions, best management practices outlined in the BACT analysis, or emissions limits change; TRP shall submit a permit modification for Department consideration (ARM 17.8.749).

C. Ash-Pulling Periods/Events

1. The requirements contained in Section II.C and II.D shall apply during ash-pulling periods/events following the completion of the "Monitoring Period" as defined in Section II.C.2 below. Ash-pulling events shall be conducted as described in *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department and included in Attachment 4 of Permit #3175-06 (ARM 17.8.749 and ARM 17.8.752).

2. $SO_2$ and $NO_x$ "Monitoring Period"

   i. Following initial startup of the boiler or commencement of commercial operations, and within 180 days after initial boiler startup following issuance of Permit #3175-06, TRP shall collect 30 days of certified NOx and $SO_2$ CEMs data to verify or establish permit limits for ash-pulling periods. TRP must collect data according to the monitoring plan as outlined in Attachment 5 (ARM 17.8.749 and ARM 17.8.752).

ii. During the monitoring period, $NO_x$ emissions from the boiler stack shall not exceed 74.0 lb/hr and $SO_2$ emissions from the boiler stack shall not exceed 155.0 lb/hr. In the event TRP demonstrates during the monitoring period, the boiler cannot meet the steady state BACT limits during ash-pulling periods, these limits (applied as BACT for startup and shutdown operations) shall be applicable for 90 days following the monitoring period (ARM 17.8.752).

iii. Within 15 days following completion of the monitoring period but no later than 195 days after initial startup of the boiler, TRP shall submit to the Department a report verifying that TRP can meet steady-state $NO_x$ and $SO_2$ emission limits (II.D.14.a. and II.D.14.c.); or TRP shall submit a permit application to modify $NO_x$ and $SO_2$ emission limits during ash-pulling periods (ARM 17.8.752).

iv. TRP shall maintain and operate all equipment including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions (ARM 17.8.749 and ARM 17.8.752).

v. During this time, best management practices and good combustion control shall apply as described in *Best Management Operating Procedures for Ash-Pulling Periods* and summarized in Attachment 4 of Permit #3175-06 (ARM 17.8.752).

D. Boiler Operations

1. Boiler heat input capacity shall be limited to 192.8 MMBtu/hr based on a 24-hour daily average and 1,688,928 MMBtu during any rolling 12-month time period (ARM 17.8.749).

2. The boiler coal-fuel feed rate shall not exceed 105,558 tons of coal during any rolling 12-month time period (ARM 17.8.749).

3. The boiler main stack shall be a minimum of 100.5 feet tall and shall be 6 feet in diameter (ARM 17.8.749).

4. $NO_x$ emissions from the boiler shall be controlled by over-fire air (OFA), flue gas recirculation (FGR), and selective non-catalytic reduction (SNCR). The OFA and FGR $NO_x$ controls shall be installed prior to initial startup of the boiler combusting any fuel, following issuance of Permit #3175-06. Beginning the date of initial solid fuel (wood-waste and/or coal) feed to the boiler after issuance of Permit #3175-06, TRP shall be allowed a 10-day operational mapping/testing period prior to installation and operation of SNCR in which to model/test the boiler for appropriate location of the SNCR equipment within the boiler furnace. SNCR shall be installed prior to any additional boiler operations following completion of the 10-day SNCR testing period (ARM 17.8.752).

5. $SO_2$ emissions from the boiler shall be controlled by a flue gas desulfurization (FGD) system when combusting coal. The FGD shall be installed prior to initial startup of the boiler following issuance of Permit #3175-06 (ARM 17.8.752).

6. PM/particulate matter with an aerodynamic diameter less than or equal to 10 microns ($PM_{10}$) emissions from the boiler shall be controlled by a fabric filter baghouse (DC5) (ARM 17.8.752).

7. Carbon monoxide (CO) and Volatile Organic Compound (VOC) emissions from the boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

8. Hydrochloric acid (HCl) gas, sulfuric acid mist ($H_2SO_4$), and mercury (Hg) emissions from the boiler shall be controlled by a FGD unit in combination with a fabric filter baghouse (ARM 17.8.752).

9. The boiler may be fired with coal and/or wood-waste biomass only except for periods of boiler startup and shutdown, as specified in Section II.B (ARM 17.8.749).

10. The sulfur content of any coal fired in the TRP boiler shall not exceed 0.745 lb S/MMBtu (ARM 17.8.752).

11. Coal fired in the boiler shall have a minimum heating value of 8,000 Btu/lb (ARM 17.8.749).

12. The sulfur content of any coal fired at TRP shall not exceed 1% by weight (ARM 17.8. 752).

13. TRP shall not cause or authorize to be discharged into the atmosphere from the fabric filter baghouse controlling emissions from the boiler (boiler Baghouse – DC5) any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340 and 40 CFR 60.43b(f), Subpart Db).

14. Except during periods of boiler startup and shutdown, as specified in Section II.B, emissions from the boiler shall not exceed the following:

    a. $NO_x$ Emissions:

        i. 47.24 lb/hr, based on a 1-hr average (ARM 17.8.749).
        ii. 0.280 lb/MMBtu averaged over the initial 10-day SNCR mapping/testing period prior to installation and initial operation of SNCR, as specified in Section II.C.4. This emission limit shall expire upon installation of SNCR (ARM 17.8.749).
        iii. After installation of SNCR, $NO_x$ emissions from the Boiler stack shall not exceed 0.196 lb/MMBtu based on a rolling 30-day average (ARM 17.8.749).

    b. CO Emissions:

        i. 0.259 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
        ii. 49.92 lb/hr, based on a 1-hr average (ARM 17.8.752).

    c. $SO_2$ Emissions:

        i. 0.220 lb/MMBtu, based on a rolling 30-day average (ARM 17.8.752); and
        ii. 72.3 lb/hr, based on a 1-hr average (ARM 17.8.749).

    d. $PM/PM_{10}$ Emissions:

        i. 5.90 lb/hr, based on a 1-hr average (ARM 17.8.752); and

ii. 0.017 grains per dry standard cubic foot (gr/dscf)*, based on a 1-hr average (ARM 17.8.752).

* The grain loading limit in Section II.D.14.d(ii) is the boiler Baghouse (DC5) limit.

e. VOC Emissions:

i. 0.0308 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
ii. 5.93 lb/hr, based on a 1-hr average (ARM 17.8.752).

f. HCl Emissions:

i. 0.01125 lb/MMBtu, based on a 1-hr average (ARM 17.8.752);
ii. 2.17 lb/hr, based on a 1-hr average (ARM 17.8.752); and
iii. 9.50 ton/year (ARM 17.8.749).

E. Boiler Pre-Heater Operations

1. The boiler pre-heater shall be limited to a maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The boiler pre-heater shall be fired on propane or diesel fuel only (ARM 17.8.749).

3. The boiler pre-heater shall be limited to a maximum of 500 hours of operation during any rolling 12-month time period (ARM 17.8.749).

4. The boiler pre-heater shall be equipped with an automatic shut-off device, which is activated when the coal and/or wood-waste biomass fuel feeder becomes operational. Boiler pre-heater operations shall be limited to startup, shutdown, malfunction, and boiler commissioning operations. TRP shall not operate the boiler pre-heater when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

F. Boiler Refractory Brick Curing Heaters

1. TRP may operate propane-fired boiler refractory brick pre-heaters only for the purpose of curing boiler refractory brick. The refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The refractory curing heater(s) shall be limited to a maximum of 500 hours of operation per heater during any rolling 12-month time period (ARM 17.8.749).

3. TRP shall not operate the refractory curing heater(s) when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

G. Coal Fuel Handling and Storage Operations

1. All railcar coal deliveries/transfers shall be unloaded via a bottom dump into an under-track hopper. $PM/PM_{10}$ emissions from railcar transfers to the under-track hopper shall be enclosed and controlled by a fabric filter baghouse (Fuel Handling Baghouse – DC1) (ARM 17.8.752).

2. $PM/PM_{10}$ emissions from the Fuel Handling Baghouse – DC1 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. Coal shall be delivered via conveyor (C1 and C2) to the day-bin coal silo (S1) prior to boiler feed. $PM/PM_{10}$ emissions from C1 coal loading shall be controlled by a partially enclosed (3-sided) hopper and vented to DC1. S1 shall be enclosed and vented to a fabric filter bin vent (Fuel Handling Bin Vent – DC2) (ARM 17.8.752).

4. $PM/PM_{10}$ emissions from the Fuel Handling Bin Vent – DC2 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

5. All material transfer conveyors for coal fuel storage and handling operations shall be limited to a maximum of 200 tons per hour capacity and shall be enclosed and vented to DC1 and/or DC2 (ARM 17.8.752).

6. TRP shall install and maintain wind fencing and an earthen berm to control fugitive dust emissions resulting from outdoor coal storage piles and operations. Further, TRP shall use reasonable precautions to control fugitive dust emissions from coal pile storage operations. Reasonable precautions shall include, but not be limited to, minimizing the number of coal pile disturbances, minimizing the area of coal pile disturbances, minimizing the fall distance of coal pile storage operations, and the use of wet dust suppression, as necessary, to control fugitive dust emissions from coal pile storage operations (ARM 17.8.752).

7. Outdoor coal storage shall be limited to a maximum of 6,000 tons at any given time (ARM 17.8.749).

H. Wood-Waste/Biomass Fuel Handling and Storage Operations

1. Wood-waste biomass fuel shall be delivered to the boiler via a pneumatic conveyor system. The pneumatic conveyor shall be enclosed and vented through the boiler and DC5 (ARM 17.8.752).

2. On-site wood-waste biomass storage shall be limited to a maximum of 3,000 tons at any given time (ARM 17.8.749).

I. Lime Handling and Storage Operations

1. All lime shall be stored in an enclosed silo. TRP shall install and operate a fabric filter bin vent (Lime Silo Bin Vent – DC3) to control $PM/PM_{10}$ emissions from the lime silo supplying the dry-lime scrubber (ARM 17.8.752).

2. $PM/PM_{10}$ emissions from the Lime Silo Bin Vent – DC3 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

J. Ash (Fly Ash and Bottom Ash) Handling and Storage Operations

1. All ash (fly and bottom ash) produced during boiler operations shall be stored in enclosed silos. TRP shall install and operate fabric filter bin vents (Fly Ash Silo Bin Vent – DC4 & Bottom Ash Silo Bin Vent – DC6) to control $PM/PM_{10}$ emissions from the ash silos collecting boiler bottom ash/fly ash (ARM 17.8.752).

2. $PM/PM_{10}$ emissions from the Fly Ash Silo Bin Vent – DC4 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. $PM/PM_{10}$ emissions from the Bottom Ash Silo Bin Vent – DC6 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

4. All fly ash transfers to trucks shall be gravity fed through a retractable load-out spout (ARM 17.8.749).

5. All bottom ash transfers to trucks shall utilize a partial (3-sided) enclosure to control fugitive dust emissions (ARM 17.8.749).

K. Testing Requirements

1. Compliance with the $NO_x$ emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the boiler following installation of the SNCR system, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP shall conduct performance source testing for $NO_x$ and CO, concurrently. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR 60, Subpart Db).

2. Compliance with the $PM/PM_{10}$ emission limits for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue annually or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR 60, Subpart Db).

3. Compliance with the opacity limit for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, and ARM 17.8.749, and 40 CFR 60, Subpart Da).

   After the initial source test monitoring compliance with the boiler/boiler Baghouse – DC5 opacity limit, TRP shall use the data from the continuous opacity monitoring system (COMS) to monitor continued compliance with the applicable opacity limit (ARM 17.8.749).

4. Compliance with the CO emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP shall conduct the performance source testing for CO and $NO_x$, concurrently. After the initial source test, testing shall continue on an every 2-

year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, 40 CFR Part 60, Subpart A, and 40 CFR 60, Subpart Db).

5. Compliance with the $SO_2$ emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105 and ARM 17.8.749).

6. Compliance with the HCl emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 4-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105).

7. TRP shall provide the Department with a record of the amount of coal being combusted and a coal analysis including sulfur content (including sulfur percent (by weight) and sulfur heat content, reported in lb/MMBtu), chlorine content, ash content, and Btu value during all compliance source tests on the boiler (ARM 17.8.749 and ARM 17.8.106).

8. Compliance with the opacity limit for the Fuel Handling Baghouse – DC1 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

   Compliance with the $PM/PM_{10}$ emission limits for the Fuel Handling Baghouse – DC1 shall be monitored by a performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

9. Compliance with the opacity limit for the Fuel Handling Bin Vent – DC2 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

Compliance with the $PM/PM_{10}$ emission limits for the Fuel Handling Bin Vent – DC2 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

10. Compliance with the opacity limit for the Lime Silo Bin Vent – DC3 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the $PM/PM_{10}$ emission limits for the Lime Silo Bin Vent – DC3 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

11. Compliance with the opacity limit for the Fly Ash Silo Bin Vent – DC4 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the $PM/PM_{10}$ emission limits for the Fly Ash Silo Bin Vent – DC4 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

12. Compliance with the opacity limit for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the $PM/PM_{10}$ emission limits for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

13. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

14. The Department may require further testing (ARM 17.8.105).

L. Operational Reporting and Recordkeeping Requirements

1. TRP shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. TRP shall maintain on site records of all coal analyses conducted in accordance with the coal sampling requirement. TRP shall submit a summary of all coal analyses to the Department by February 15 of each year; the information may be submitted along with the annual emission inventory (ARM 17.8.505 and ARM 17.8.749).

3. TRP shall maintain on site records of all annual COMS/CEMS certifications. The records shall be maintained by TRP for at least 5 years following the date of the measurement, must be available at the facility site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. TRP shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by TRP as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

6. TRP shall document, by month, the boiler heat input value. By the 25$^{th}$ day of each month, TRP shall total the heat input in MMBtu for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory. TRP shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

7. TRP shall document, by day, the boiler heat input value in MMBtu/hr on a 24-hr calendar-day average. TRP shall maintain a heat input monitoring system capable of demonstrating compliance with the 24-hr calendar-day heat input limit. TRP shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

8. TRP shall document, by month, the coal feed rate to the boiler in tons/month. By the 25$^{th}$ day of each month, TRP shall total the total tons of coal feed to the boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

9. TRP shall maintain records monitoring compliance with all applicable fuel use requirements (ARM 17.8.749).

10. TRP shall maintain records monitoring compliance with the coal type (including sulfur content in lb S/MMBtu) and heating value requirements (ARM 17.8.749).

11. TRP shall document, by month, the boiler pre-heater operating hours. By the 25th day of each month, TRP shall total the boiler pre-heater operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

12. TRP shall document, by month, the refractory curing heater(s) operating hours. By the 25th day of each month, TRP shall total each of the refractory curing heater(s) operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

13. TRP shall maintain records monitoring compliance with the outdoor coal storage limit of 6,000 tons at any given time (ARM 17.8.749).

14. TRP shall maintain records monitoring compliance with the outdoor wood-waste storage limit of 3,000 tons at any given time (ARM 17.8.749).

15. TRP shall document each boiler startup and shutdown event. The boiler startup and shutdown event documentation shall include, at a minimum, the reason/basis for the startup or shutdown event, the duration of the startup or shutdown event (in hours), and the procedures used to conduct and complete the startup or shutdown event. The information shall be submitted to the Department upon request (ARM 17.8.749)

M. Monitoring Requirements

1. TRP shall install, operate, and maintain the applicable COMS and $NO_x$ CEMS to monitor compliance with the applicable boiler emission limits. $NO_x$ and opacity emissions monitoring shall be subject to 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control) provisions. TRP shall conduct a Relative Accuracy Test Audit (RATA) for the $NO_x$ CEMS and shall inspect and audit the COMS annually, using neutral density filters (EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors; EPA-450/4-92-010, April 1992). The annual monitor RATA/audit may coincide with the required compliance source testing (ARM 17.8.749).

2. TRP shall install, operate, and maintain the applicable $SO_2$ CEMS to monitor compliance with the applicable boiler emission limits. TRP shall install the $SO_2$ CEMS prior to initial operation of the boiler following. TRP is not subject to the $SO_2$ monitoring requirements contained in 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control); however, for the purpose of maintaining established and accepted monitoring protocol, TRP shall comply with the $SO_2$ CEMS monitoring requirements of these provisions. TRP shall conduct an annual RATA for the $SO_2$ CEMS. The annual monitor RATA may coincide with the required compliance source testing (ARM 17.8.749).

3. All stack testing shall be conducted according to 40 CFR Part 60, Appendix A, 40 CFR 60, Subpart Db, and ARM 17.8.105, Testing Requirements Provisions. Test methods and procedures, where there is more than one option for any given pollutant, shall be approved by the Department in writing prior to commencement of testing (ARM 17.8.106 and ARM 17.8.749).

4. Monitoring data shall be maintained for a minimum of 5 years at the TRP facility (ARM 17.8.749).

N. Ambient Air Monitoring

Following issuance of Permit #3175-04, TRP may cease operation of the ambient air quality monitoring station required under Permit #3175-02. However, beginning on the date of initial startup of the boiler after issuance of Permit #3175-06, TRP shall operate a $PM_{10}$ ambient air quality-monitoring network at the project site. The monitoring requirements are fully described in the Monitoring Plan (Attachment 1). Exact monitoring locations must be approved by the Department prior to installation or relocation. TRP may not conduct initial start-up of the boiler after issuance of Permit #3175-06 until the ambient monitoring station has been located at a Department approved monitoring site (ARM 17.8.749 and ARM 17.8.204).

O. Notification

1. Within 15 days after actual startup of the boiler following issuance of Permit #3175-06, TRP shall notify the Department of the date of actual startup (ARM 17.8.749).

2. Within 30 days of commencement of installation of the $SO_2$ CEMS, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749).

3. Within 15 days after completed installation of the $SO_2$ CEMS, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

4. TRP shall notify the Department of the date of initial solid fuel feed (wood-waste/coal) to the boiler (ARM 17.8.749).

5. Within 30 days of commencement of installation of the SNCR unit, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749).

6. Within 15 days after completed installation of the SNCR unit, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

7. Within 30 days of commencement of installation of the FGD system, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749)

8. Within 15 days after completed installation of the FGD unit, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – TRP shall allow the Department's representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if TRP fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving TRP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board. A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b). The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure by TRP to pay the annual operation fee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked. This permit will expire 3 years after the date of permit issuance unless construction commences within that time period (ARM 17.8.762).

ATTACHMENT 1
Permit #3175-06

Ambient Air Monitoring Plan
Thompson River Power, LLC

1. This ambient air monitoring plan is required by MAQP #3175-06, which applies to TRP's electrical and steam co-generation operations near Thompson Falls, in Sanders County, Montana. This monitoring plan may be changed by the Department. All current requirements of this plan are considered conditions of MAQP #3175-06.

2. TRP shall install, operate, and maintain a single ambient air quality monitoring station in the vicinity of plant. The exact location of the monitoring site must be approved by the Department and must meet all siting requirements contained in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; and Parts 50, 53, and 58 of the Code of Federal Regulation (CFR); or any other requirements specified by the Department.

3. TRP shall continue air monitoring for at least 5 years after implementation of the ambient air monitoring plan. At that time, the air monitoring data will be reviewed by the Department and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions for the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

4. TRP shall monitor the following parameters at the sites and frequencies described below:

| Location | Site | Parameter | Frequency |
|---|---|---|---|
| Plant Area<br>30-089-0009 | Thompson<br>River Power<br>HWY 200 | $PM_{10}$[1]<br>Local Conditions: 85101<br>Standard Conditions: 81102 | Every 3rd day[2]<br>according to EPA<br>monitoring schedule |
| [1]$PM_{10}$ = particulate matter less than 10 microns.<br>[2]Every 3rd day throughout the year (1/3 schedule) | | | |

5. Data recovery (DR) for all parameters shall be at least 80%, computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. The data recovery shall be calculated using the following equation(s), as applicable:

$$\textit{Manual Methods \% DR} = \left[\frac{\textit{total number of valid samples collected}}{\textit{total number of samples scheduled}}\right] X\,100$$

or

$$\textit{Automated Methods \% DR} = \left[\frac{\textit{total number of hours possible} - \textit{hours lost to QA/QC checks} - \textit{hours lost to downtime}}{\textit{total number of hours possible}}\right] X\,100$$

6. Any ambient air monitoring changes proposed by TRP must be approved in writing by the Department.

7. TRP shall utilize air monitoring and quality assurance procedures which are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; 40 CFR Parts 53 and 58; and any other requirements specified by the Department.

8. TRP shall submit quarterly data reports within 45 days after the end of the calendar quarter and an annual data report within 90 days after the end of the calendar year. The annual report may be substituted for the fourth quarterly report if all information in Item 9 below is included in the report.

9. The quarterly data submittals shall consist of a hard copy narrative data summary and a digital submittal of all data points in AIRS batch code format. The electronic data must be submitted to the Air Monitoring Section as digital text files readable by an office PC with a Windows operating system.

   The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

   a. A hard copy of the individual data points,

   b. The first and second highest 24-hour concentrations for $PM_{10}$,

   c. The quarterly and monthly wind roses,

   d. A summary of the data completeness,

   e. A summary of the reasons for missing data,

   f. A precision data summary,

   g. A summary of any ambient air standard exceedances, and

   h. Q/A-Q/C information such as zero/span/precision, calibration, audit forms, and standards certifications.

10. The annual data report shall consist of a narrative data summary. The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

   a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

   b. The year's four highest 24-hour concentrations for $PM_{10}$,

   c. The annual wind rose,

   d. A summary of any ambient air standard exceedances, and

   e. An annual summary of data completeness.

14. All records compiled in accordance with this Attachment must be maintained by TRP as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

15. The Department may audit (or may require TRP to contract with an independent firm to audit) the air monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times.

16. The hard copy reports should be sent to:

Department of Environmental Quality
Attention: Air Compliance Section Supervisor

17. The electronic data from the quarterly monitoring shall be sent to:

Department of Environmental Quality
Attention: Air Monitoring Section Supervisor

ATTACHMENT 2
Permit #3175-06

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS

PART 1 Complete as shown. Report total time plant operated during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit startup, shutdown, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit startup, shutdown, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1 – (CEMS downtime in hrs during the reporting period* / total hrs of point source operation during reporting period)) x 100

* All time required for calibration and to perform preventative maintenance must be included in the opacity CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TRP units, energized for ESPs; pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 The person in charge of the overall system and reporting shall certify the validity of the report by signing Part 8.

## EXCESS EMISSIONS REPORT

**PART 1**

a. Emission Reporting Period ____________________

b. Report Date ____________________

c. Person Completing Report ____________________

d. Plant Name ____________________

e. Plant Location ____________________

f. Person Responsible for Review and Integrity of Report ____________________

g. Mailing Address for 1.f. ____________________

____________________

h. Phone Number of 1.f. ____________________

i. Total Time in Reporting Period ____________________

j. Total Time Plant Operated During Quarter ____________________

k. Permitted Allowable Emission Rates: Opacity ____________________

$SO_2$ ____________ $NO_x$ ____________ TRS ____________

l. Percent of Time Out of Compliance: Opacity ____________________

$SO_2$ ____________ $NO_x$ ____________ TRS ____________

m. Amount of Product Produced During Reporting Period ____________________

n. Amount of Fuel Used During Reporting Period ____________________

**PART 2 - Monitor Information: Complete for each monitor.**

a. Monitor Type (circle one)

Opacity $SO_2$ $NO_x$ $O_2$ $CO_2$ TRS Flow

b. Manufacturer ______________________________

c. Model No. ______________________ ______________

d. Serial No. ______________________

e. Automatic Calibration Value: Zero ______________ Span ______________

f. Date of Last Monitor Performance Test ______________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________

2) During plant operation ______________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ______________________

i. Conversion Factor (f-Factor, etc.)

j. Location of monitor (e.g. control equipment outlet)

**PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant)**

a. Pollutant (circle one):

Opacity $SO_2$ $NO_x$ TRS

b. Type of Control Equipment ______________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

______________________________________________

d. Date of Control Equipment Performance Test ______________________

e. Control Equipment Operating Parameter During Performance Test

______________________________________________

______________________________________________

______________________________________________

______________________________________________

**PART 4 - Excess Emission (by Pollutant).**

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

**PART 5 - Continuous Monitoring System Operation Failures.**

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

**PART 6 - Control Equipment Operation During Excess Emissions.**

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

**PART 7 - Excess Emissions and CEMS performance Summary Report.**

Use Table IV: Complete one sheet for each monitor.

**PART 8 - Certification for Report Integrity, by person in 1.f.**

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ______________________________

NAME ______________________________

TITLE ______________________________

DATE ______________________________

TABLE I

EXCESS EMISSIONS

| Date | Time From | Time To | Duration | Magnitude | Explanation/Corrective Action |
| --- | --- | --- | --- | --- | --- |

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

| Date | Time From | Time To | Duration | Problem/Corrective Action |
|---|---|---|---|---|

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

| Date | Time From | Time To | Duration | Operating Parameters | Corrective Action |
|---|---|---|---|---|---|

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): $SO_2$ $NO_x$ TRS $H_2S$ CO Opacity

Monitor ID

| Emission data summary [1] | **CEMS performance summary [1]** |
|---|---|
| 1. Duration of excess emissions in reporting period due to:<br><br>a. Startup/shutdown<br>b. Control equipment problems<br>c. Process problems<br>d. Other known causes<br>e. Unknown causes<br><br>2. Total duration of excess emissions<br><br>3. $\left[ \frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$ | 1. CEMS[2] downtime in reporting due to:<br><br>a. Monitor equipment malfunctions<br>b. Non-monitor equipment malfunctions<br>c. Quality assurance calibration<br>d. Other known causes<br>e. Unknown causes<br><br>2.Total CEMS downtime<br><br>3. $\left[ \frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$ |
| | |

[1] For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
[2] CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

ATTACHMENT 3
Boiler Startup and Shutdown Procedures
Permit #3175-06

Introduction

The requirements contained in Section II.B of Montana Air Quality Permit #3175-06 shall apply during Babcock and Wilcox spreader stoker boiler (boiler) startup and shutdown operational events. TRP shall operate the facility in accordance with the *Best Management Operational Practices for Startup and Shutdown Events* submitted to the Department on July 29, 2008. In the event that the *Best Management Operational Practices Startup and Shutdown Events* on file with the Department are modified significantly to the extent that would result in a change in boiler emissions, best management practices outlined the BACT analysis, or emissions limits, TRP shall submit these modifications to the Department for inclusion in Department record and shall submit a permit modification, when applicable. The following summarizes the startup and shutdown operations that shall be conducted. The entire startup and shutdown procedure is on file with the Department.

Although the steps for performing a boiler startup or shutdown event are generally the same, the amount of effort, inspection level, and duration of the event may vary significantly for each event. The most important factors governing the startup or shutdown procedures include, but are not limited to: boiler temperature, chemistry of the water in the boiler drum, condition of the coal bed, condition of the coal burning grates, condition of the steam-driven turbine, and condition of auxiliary systems, such as pumps and electrical gear. All of these factors can significantly influence the duration and exact actions taken during a startup or shutdown event. The following startup and shutdown procedures generally describe typical operational procedures used by TRP during a boiler startup or shutdown event.

Startup Procedures

A startup event takes the facility from a non-operational condition to a steady-state electrical load condition. During the startup process, the facility goes through a number of steps to go from a cold start or a warm re-start until the system is brought up to a steady-state load. During this process, oxides of nitrogen ($NO_x$) and sulfur dioxide ($SO_2$) emissions will vary until conditions for the safe and effective operation of the applicable $NO_x$ and/or $SO_2$ air pollution control equipment are reached. Particulate emissions are captured by the baghouse at all times of operation, including periods of startup.

**Cold-Start Conditions**

A cold-start event occurs when there is no fuel feed to the boiler and the low temperature of the boiler requires the initial use of the propane/diesel-fired startup burner to bring the pressure of the boiler up to 50 PSIG.

Step 1. Perform all pre-startup inspections.
Step 2. Establish a uniform coal bed on the boiler grate. This protects the boiler grate from radiant heat damage from the startup burner and assures proper lighting and combustion of the coal pile.
Step 3. Start the induced draft (ID) fan, and balance the airflow.
Step 4. Start the startup burner and follow the B&W recommended warm-up curve until the steam drum pressure reaches 50 psig. The startup commences upon ignition of the startup burner (Estimated time for Step 4: 8-12 hours).
Step 5. Turn off the startup burner, and secure it against operation during periods of coal/wood fuel feed. Turn off the ID fan. Ignite the coal with a hand-held propane torch, close the access doors, restart the ID fan, and start Flue Gas Recirculation (FGR) Fan-01 (Estimated time for Step 5: 2 - 3 hours).

Step 6. Once the coal fire is well established, start the coal feeder, the forced-draft (FD) fan, the fly-ash reinjection fan, and the over-fire air (OFA) fan. The control system automatically ramps up the fuel feed rate to maintain boiler pressure. FGD system operation is initiated when the temperature at the inlet of the scrubber is 250°F and the temperature of the baghouse inlet is 195°F. Urea injection operation is initiated when the fire box (15 ft. above grate) temperature is approximately 1512°F. (Note: these temperatures to be confirmed during plant commissioning.) The plant startup is complete when both the FGD and urea injection systems are operational, and the lbs/MMbtu emission limits in Section II.B of Montana Air Quality Permit #3175-06 have been met for at least 15 minutes (Estimated time for Step 6: 4 – 8 hours).

Total elapsed time from cold start to full load typically varies between 12 and 48 hours.

**Warm-Start Conditions**

A warm-start occurs when the boiler temperature is elevated and the boiler drum pressure is above 15 psig, but there is no fuel feed to or electrical output from the boiler. A warm-start uses the same procedure as described in the cold-start procedure discussed above except the procedure is initiated at Step 4, depending on the condition of the boiler and turbine at time of re-start.

Shutdowns

A shutdown event takes the boiler from a steady-state electrical load condition to a non-operational condition or from a mid startup condition to a non-operating condition. During this process, NOx and $SO_2$ emissions are controlled by the applicable emission control systems until the boiler operating parameters can no longer support the operation of the respective controls, as discussed in the startup procedures. Particulate emissions are captured by the baghouse at all times of operation, including periods of shutdown.

Step 1. Decrease the fuel feed and combustion air flow rates. As the rate of fuel feed is reduced, the steam production rate decreases. Close the manual slide gate on the outlet of the Boiler Coal Silo. Continue to burn clear of the Weigh Scale Conveyor. Stop the Coal Weigh Scale Conveyor and Weighing Hopper batch cycle. Shut down the coal feeder when the coal feed chute is empty and feeders are clear of coal. When the flue gas inlet temperature to the FGD drops to 195°F, remove the FGD and urea injection systems from service. Shut down the stoker grate operation when the stoker is clear and all ash and coal has run out. The shutdown commences at the start of the first 15-minute period when the lbs/MMbtu emission limits in Section II.B of MAQP #3175-06 have been exceeded after initiation of the shutdown procedure. The shutdown ends when the stoker grate has been shut down.
(Estimated time for shutdown: 4 - 8 hours)

ATTACHMENT 4
Ash-Pulling Procedures
Permit #3175-06

The requirements contained in Section II.C of MAQP #3175-06 shall apply during Babcock and Wilcox spreader stoker boiler (boiler) ash-pulling periods/events. TRP shall operate the facility in accordance with the *Best Management Operating Procedures for Ash-Pulling Periods* submitted to the Department on July 29, 2008. In the event that the *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department are modified significantly to the extent that would result in a change in boiler emissions, best management practices outlined the BACT analysis, or emissions limits, TRP shall submit these modifications to the Department for inclusion in Department record and shall submit a permit modification, when applicable. The following summarizes the ash-pulling procedures that shall be conducted. The entire ash-pulling procedure is on file with the Department.

*Best Management Operating Procedures for Ash-Pulling Periods* shall be followed during ash-pulling periods to decrease the duration of the events and limit the amount of non-design air into the boiler. There are two bottom ash hoppers with associated clinker grinders located in the basement of the boiler building that collect ash. While the boiler is operating, the TRP operator is required to empty each of the bottom ash hoppers approximately every 12 hours.

**Summary of Ash-Pulling Procedures**

Step 1. Perform all pre-ash pulling inspections.

Step 2. With the slide gate in the closed position, open the clinker grinder inspection door and verify that both clinker grinders are free of debris. Once clear, close the clinker grinder inspection door.

Step 3. Establish a vacuum through ash collection system. Once a stable vacuum is achieved, start the No. 1 clinker grinder drive.

Step 4. From the bottom ash hopper inspection ports visually inspect the bottom ash level prior to dumping each bottom ash hopper. Do not open the clinker grinder inspection door while the bottom ash slide gate is in the open position. Proceed with dumping bottom ash. When required, rod the debris clear to allow continued flow to the grinder.

Step 5. Start the No. 2 clinker grinder drive.

Step 6. Begin dumping cycle for No. 1 and No. 2 Bottom Ash Hoppers

Estimated time for one ash-pulling cycle: 30-60 minutes.

ATTACHMENT 5
Ash-Pulling Monitoring Period
Permit #3175-06

This monitoring plan outlines key parameters that will be monitored during ash-pulling periods. This information will be used to determine if the proposed $NO_x$ and $SO_2$ emission limits in Section II.D are appropriate.

Following initial startup of the boiler or commencement of commercial operations, but no later than 180 days after initial boiler startup following issuance of Permit #3175-06, TRP facility will collect 30 days of certified NOx and $SO_2$ CEMs data to verify or establish permit limits for ash-pulling periods. At all times, TRP shall follow *Best Management Operating Procedures for Ash-Pulling Periods* and good combustion practices. In addition, TRP shall operate all equipment in a manner consistent with air pollution control practices for minimizing emissions.

For each ash-pulling period (occurs two times per day) the following parameters shall be monitored:

1) $NO_x$ emissions (ppmc, lb/MMBtu, lbs/hr);
2) $SO_2$ emissions (ppmc, lb/MMBtu, lbs/hr)
3) Duration and frequency of the ash-pulling period; and
4) Heat input rate (MMBtu/hr, HHV).

Monitoring

$NO_x$ and $SO_2$ Continuous emission monitoring systems (CEMs) shall be operating at all times. TRP shall evaluate all CEMs data and shall calculate the mean and standard deviation of NOx and $SO_2$ emissions during each 15-minute period, including the 15-minute period following the completion of the ash-pulling period.

Recordkeeping

1) TRP shall provide all data to the Department, as required.

2) TRP shall calculate the mean and standard deviation for all 15-minute increments when ash-pulling occurs, including the first 15-minute period following the completion of ash-pulling.

3) TRP shall provide a report to the Department within 15 days following completion of the monitoring period, but no later than 195 days after initial boiler startup following issuance of MAQP #3175-06.

Monitoring Results

Within 180 days following completion of the initial startup of the boiler or commencement of commercial operations following the issuance of MAQP #3175-06, TRP shall submit to the Department:

1) Results confirming that TRP can meet steady-state $NO_X$ and $SO_2$ emission limits outlined in Section II.D; and/or

2) A permit modification to establish new emission limits for $NO_x$ and $SO_2$ during ash pulling periods.

Permit Analysis
Thompson River Power, LLC
Permit #3175-06

I. Introduction/Process Description

A. Permitted Equipment

The following table indicates all permitted sources of emissions and emission controls utilized for each emitting unit at the Thompson River Power, LLC (TRP):

| Emitting Unit/Process | Control Device/Practice |
|---|---|
| Boiler (192.8 million British thermal unit (MMBtu/hr))<br>Permit Limit of 192.8 MMBtu/hr on a 24-hour daily average and 1,688,928 MMBtu on a rolling 12-month basis | $PM/PM_{10}$ – Baghouse DC5 (40,513 dry standard cubic feet per minute (dscfm) capacity flow)<br>$SO_2$ – Flue Gas Desulfurization (FGD) Unit<br>Hg – FGD/Baghouse<br>Acid Gases (HCl and $H_2SO_4$) – FGD/Baghouse<br>$NO_x$ – Over-Fire Air (OFA), Flue-Gas Recirculation (FGR), and Selective Non-Catalytic Reduction (SNCR) Unit. |
| Wet Cooling Tower | NA |
| Fuel Handling Operations (Coal) | Enclosures, Fuel Handling Baghouse – DC1 (2,200 cubic feet per minute (cfm)) and Fuel Handling Bin Vent – DC2 (1,000 cfm) |
| Fuel Handling Operations (Wood Waste Bio-Mass) | Enclosed Pneumatic Conveying System Vented to boiler Baghouse |
| Outdoor Coal Storage | (≤ 6,000 tons) Wind Fencing, Earthen Berm, Reasonable Precautions Including Water Spray, As Necessary |
| Outdoor Wood-Waste Biomass Storage | (≤ 3,000 tons) Wind Fencing, Earthen Berm, and Reasonable Precautions Including Water Spray, As Necessary |
| Lime Storage and Handling Operations | Enclosures, Lime Silo Bin Vent – DC3 (1,000 cfm) |
| Bottom Ash/Fly Ash Storage and Handling Operations | Enclosures, Fly Ash Bin Vent – DC4 and Bottom Ash Bin Vent – DC6 (1,000 cfm/unit), Fly-Ash Retractable Load-out Spout (Truck Transfer), Bottom-Ash Partial Enclosure (3-Sided) (Truck Transfer) |
| Truck Traffic/Haul Roads | Paved Roads, Water and/or Chemical Dust Suppressant |
| Boiler Startup Pre-Heater | Limited to 60 MMBtu/hr (total combined heat input); Diesel or Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year |
| Refractory Curing Heater(s) (Propane-Fired) | Limited to 60 MMBtu/hr; Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year Per Heater |

B. Source Description

TRP operates a 16.5-megawatt (MW) capacity coal/wood-waste biomass-fired electricity and steam co-generation plant. The plant incorporates a 192.8 MMBtu/hr capacity stoker boiler (boiler) capable of a reported 130,000 pounds of steam production per hour. Most of the steam is sent to a turbine generator for the production of electricity to be sent to the power grid with a small percentage (up to 10%) of the steam and energy produced sent directly to Thompson River Lumber Company (TRL), for use in the lumber dry kilns and general operations at the sawmill. TRP will have a parasitic load (use) of approximately 0.4 MW.

Because TRP and TRL are under separate ownership and control and are covered under separate Standard Industrial Classification (SIC) codes, the two sources are considered separate sources.

The boiler is supported by coal and wood-waste biomass fuel handling system(s), including outdoor fuel storage; a cooling tower; a lime handling system; an ash/fly ash handling system; and various support trucks/vehicles. The boiler and supporting facilities incorporate various emission control devices to limit potential pollutant emissions from each source.

The boiler is equipped with OFA, FGR, and an SNCR system to control oxides of nitrogen ($NO_x$) emissions, a combination of low sulfur coal and a FGD in tandem with the boiler baghouse to control sulfur dioxide ($SO_2$) emissions, the same FGD and baghouse to control mercury (Hg), hydrochloric acid (HCl), and other acid gas emissions, combustion control to limit carbon monoxide (CO) emissions, a baghouse to control particulate matter/particulate matter with an aerodynamic diameter less than or equal to 10 microns ($PM/PM_{10}$) emissions, and proper design and combustion to control Volatile Organic Compound (VOC) emissions. Boiler combustion gases first enter the FGD then pass through the boiler baghouse and eventually vent to the atmosphere through the boiler main stack.

The boiler fires low-sulfur coal and/or wood waste bio-mass only, except for periods of startup, shutdown, malfunction, and boiler commissioning where the 60 MMBtu/hr propane or diesel fired boiler pre-heater is in operation. The boiler pre-heater cannot be in operation while the boiler is producing energy or the boiler fuel feed system is operating, and the unit is limited to a maximum of 500 hours of operation during any rolling 12-month time period. In addition, TRP's boiler must fire low-sulfur coal ($\leq$ 0.745 pounds sulfur/MMBtu) and the facility must follow the procedures summarized in Attachment 3 and further described in Best Management Operational Practices for Startup and Shutdown on file with the Department.

Coal is delivered by railcar and unloaded to an under-track hopper. Air displaced from the under-track hopper is vented to DC1. Some coal is stored in the under track hopper while the majority of coal is transferred from the under-track hopper, via front-end loader, to an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from coal storage operations. From the under-track hopper and the outdoor coal storage area, coal is transferred, via a front-end loader, to a 3-sided feed hopper and on to a 200 tons per hour (ton/hr) capacity enclosed conveyor (C1) that will transfer coal to a second 200 ton/hr capacity enclosed conveyor (C2) that will unload to an enclosed day-bin silo (S1) on top of the boiler-house. Air displaced from the transfer between the front-end loader and the feed-hopper and the conveyor transfer points between the feed-hopper and C1 and C1 to C2 is vented to DC1 while air displaced from the transfer between C2 and S1 is vented to DC2.

Additionally, wood waste is delivered to the site for storage until use is needed. Wood-waste biomass is stored in an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from wood-waste storage operations. From the on-site storage area, wood-waste is transferred to the adjacent TRL, for processing into fuel grade wood-waste. After processing at the TRL site, the fuel grade wood-waste is pneumatically transferred through an enclosed pneumatic conveying system to the TRL boiler. After reaching the TRL boiler, the wood-waste enters a cyclone (CS1), and is then transferred directly into the boiler through the OFA ports. Air entering the boiler via the wood-waste biomass pneumatic feed is directly vented through the boiler baghouse (DC5). The transfer of fuel from S1 to the boiler is controlled by negative pressure from the boiler.

Lime for use in the FGD is delivered by trucks and pneumatically conveyed to a 1,000-ton capacity storage silo (S3). From S3 lime is pneumatically conveyed to the FGD. Air that is displaced from S3 is vented through DC3.

Combustion in the boiler produces bottom ash and fly ash. The ash is temporarily stored in silos on site including fly-ash silo (S4) and bottom-ash silo (S5). Bottom-ash from S5 is gravity-fed through a partial enclosure (3-sided enclosure) to a truck for removal from the site while fly ash from S4 is gravity fed through a retractable load out spout to a truck for removal from the site. Air displaced from the transfer between trucks and S4 and S5 is vented to DC4 and DC6.

A cooling tower is used to dissipate heat from the boiler by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower uses an induced counter flow draft incorporating 3 cells. The make up rate for the cooling tower is approximately 125 gallons per minute.

C. Permit History

On November 9, 2001, Thompson River Co-Gen, LLC (TRC) was issued final **Montana Air Quality Permit (MAQP) #3175-00** for the construction and operation of a 12.5-MW capacity electrical and steam co-generation plant. The plant was permitted for a 156 MMBtu/hr heat input capacity coal and wood-waste biomass-fired boiler and associated fuel handling, storage, and support facilities.

On September 7, 2004, the Montana Department of Environmental Quality (Department) received a complete application for proposed modifications to the permitted TRC operations. Based on the information contained in the complete permit application, the following modifications were proposed under **MAQP #3175-01**:

- Increase in the allowable boiler baghouse emission rate (lb/hour) for $PM/PM_{10}$. The previously permitted Best Available Control Technology (BACT) emission limit determination of 0.017 grains per dry standard cubic feet (gr/dscf) of air-flow through the boiler baghouse would remain applicable to the baghouse-controlled boiler operations. However, due to the increase in capacity air-flow through the baghouse the permit action resulted in an increased allowable PM and $PM_{10}$ emission rate of 5.90 lb/hr;
- Incorporation of an enforceable boiler I.D. fan flow capacity of 70,000 acfm, calculated as 40,513 dry standard cubic feet per minute (dscfm);
- Increase in the facility electrical output capacity from 12.5 MW to 16.5 MW;
- Incorporation of an enforceable boiler heat input capacity limit of 192.8 MMBtu/hr and 1,688,928 MMBtu/yr. This limit would be monitored on a continuous basis using information obtained from the required coal analysis and published wood-waste fuel specifications. Based on the hourly limit, the source is below the listed New Source Review – Prevention of Significant Deterioration (NSR/PSD) heat input threshold value of 250 MMBtu/hr;
- Incorporation of an enforceable annual maximum boiler coal feed limit of 105,558 tons during any rolling 12-month time period. This limit is based on the maximum boiler heat input capacity feed rate of 192.8 MMBtu/hr and the worst case coal heating value of 8,000 Btu/lb;

- Incorporation of enforceable boiler main stack minimum requirements of 100.5 feet tall and 6 feet in diameter;
- Incorporation of an enforceable minimum coal heating value of 8,000 British thermal units per pound (Btu/lb) of coal;
- Incorporation of an enforceable maximum sulfur in coal value of 1.0% sulfur by weight;
- Incorporation of new $NO_x$, CO, VOC, $SO_X$, and HCl BACT emission limits for boiler operations. The BACT analyses and determination(s) for modified boiler emissions were conducted due to the increased boiler heat input capacity. A BACT analysis and determination summary was provided in the permit analysis to MAQP #3175-01;
- Incorporation of an enforceable coal conveyor maximum capacity of 200 ton/hr for each coal handling conveyor at the TRC site;
- Incorporation of an enforceable partial (3-sided) enclosure requirement for coal conveyor loading en-route to the coal day bin S1;
- Addition of a 60 MMBtu/hr capacity diesel and/or propane-fired boiler pre-heater to the existing permitted equipment at the facility. The pre-heater would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and would be limited to a maximum of 500 hours of operation per year;
- Addition of refractory curing heaters with a maximum combined heat input capacity of 60 MMBtu/hr to the existing permitted equipment at the facility. The refractory curing heaters would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and each heater would be limited to a maximum of 500 hours of operation during any rolling 12-month time period;
- Modification of the permitted BACT requirement for primary coal storage within a baghouse controlled silo. Outdoor storage of coal utilizing wind fencing, earthen berm, and water spray, as necessary, to control fugitive coal storage $PM/PM_{10}$ emissions would replace the initial BACT determination under MAQP #3175-00. A summary of the BACT analysis used to make the new outdoor fuel storage BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Addition of on-site wood-waste biomass storage operations utilizing wind fencing, earthen berm, and water spray, as necessary, as BACT control of fugitive wood-waste biomass storage $PM/PM_{10}$ emissions. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Revisions to the previously permitted ash handling operations for the addition of a second ash handling bin vent under a new BACT determination. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Incorporation of an enforceable coal storage limit of 6,000 tons at any given time;
- Incorporation of an enforceable on-site wood-waste storage limit of 3,000 tons at any given time; and
- Incorporation of $PM_{10}$ ambient air quality monitoring requirements into the permit.

Also, TRC requested that the Department modify the previously permitted BACT requirement that all fuel transfer conveyors be enclosed to require that all fuel transfer conveyors must be covered. TRC constructed coal fuel conveyors incorporating a cover, which extends past the conveyor, creating, in effect, an enclosed conveying system. Further, TRC proposed the construction of a fully enclosed pneumatic conveying system for wood-waste biomass fuel. The Department determined that these conveying systems constitute enclosed fuel transfer conveyors; therefore, the Department will not modify the permit to require covered versus enclosed conveyors.

Because many of the above cited permit modifications affected the concentration of and plume rise and dispersion characteristics of pollutants resulting from modified TRC operations, the Department determined that air dispersion modeling was required to demonstrate compliance with applicable National and Montana Ambient Air Quality Standards (NAAQS/MAAQS). A summary of air dispersion modeling results is contained in Section VI, Ambient Air Quality Impacts, of the permit analysis for MAQP #3175-01.

The preliminary determination (PD) was open for public comment from October 8, 2004, through October 25, 2004. Based on comments received during the public comment period, the Department modified the PD as follows:

- Incorporation of an enforceable requirement for coal fuel chlorine and ash content reporting during all source testing (Section II.C.5);
- Correction of the ambient air impact analysis summary to indicate the correct information analyzed (Section VI of the Permit Analysis and Section 7.F of the EA);
- The dry lime scrubber BACT control requirement was referenced as a FGD throughout the Department decision and permit analysis for consistency and clarification of terms;
- Modification of the language contained in Section II.A.26 of the PD from the "on-site" coal storage limit of 6,000 tons to the analyzed and intended "outside" coal storage limit of 6,000 tons;
- Incorporation of increased $PM_{10}$ ambient air quality monitoring schedule. The Department maintains that a single ambient air quality monitor remains appropriate; however, the Department modified the ambient monitoring schedule to require sample analysis on an every 3rd day schedule year round; and
- Incorporation of an enforceable boiler steam production limit in place of the electrical megawatt production limit included in the PD (Section II.A.1).

MAQP#3175-01 replaced MAQP #3175-00.

On February 24, 2005, the Department received from TRC a notice of an administrative error contained in TRC's MAQP #3175-01. Specifically, Section II.C, Testing Requirements, did not include a specific testing schedule for $NO_x$ emissions from the boiler, while Section II.B clearly specified that boiler $NO_x$ emission limits are subject to source testing. MAQP #3175-01 did include provisions enabling the Department to invoke boiler $NO_x$ source testing; however, at the request of TRC and in the interest of providing clarification for boiler $NO_x$ source testing requirements, the current permit action amended the permit to include the appropriate $NO_x$ source testing schedule under the provisions of ARM 17.8.764(1)(c). The amended $NO_x$ source-testing requirement was included in Section II.C.1 of MAQP #3175-02.

Further, on April 8, 2005, TRC submitted a request for an additional permit amendment under the provisions of ARM 17.8.764(1)(b) to change the existing Method 5 source-testing schedule for various permitted emitting units, maintain and specify the implied Method 9 source testing schedule, and accurately characterize certain emitting unit control technologies as fabric filter bin vents. In the initial application for MAQP #3175-00 and subsequent MAQP modification #3175-01, emitting units DC-2 (Fuel Handling Bin Vent), DC-3 (Lime Silo Bin Vent), DC-4 (Fly-Ash Silo Bin Vent), and DC-6 (Bottom-Ash Silo Bin Vent) were inconsistently characterized as varied types of fabric filter dust collecting systems (i.e. baghouses, bin vents, and/or dust collectors) and inaccurately characterized as having a continuous air-flow. These units are actually fabric filter bin vents, which control particulate emissions using natural draft or simple air displacement within the associated silo, or similar unit, to provide air flow through the filter. Given this information, the Department determined that the appropriate permit limit(s) for the affected units remained 20% opacity and a grain-loading limit of 0.02 gr/dscf. In accordance with Department fabric filter bin vent testing guidance the Department determined that the appropriate compliance demonstration for these units is an initial and periodic Method 9 source testing. Therefore, under the provisions of ARM 17.8.764(1)(b), the Department is amending the permit to remove the implied initial Method 5 source test requirement for the affected units and maintain initial and periodic Method 9 source testing. However, the Department maintained the authority to require a Method 5 source test demonstration for the affected units. Further, the permit action re-characterized all affected units as bin vents throughout the permit to clarify the nature of the control device.

In addition, since TRC has accomplished various notification requirements contained in Section II.G of MAQP #3175-01, those affected notifications were removed from the permit. **Permit #3175-02** replaced Permit #3175-01.

On January 4, 2006, the Department received a complete application for the modification of TRC's MAQP #3175-02. The application was assigned **Permit #3175-03**. Specifically, TRC requested various changes to applicable permit terms and conditions relating to the Babcock and Wilcox Spreader-Stoker boiler. On February 10, 2006, the Department issued a PD on MAQP #3175-03 for the proposed modification of the TRC air quality permit. On March 13, 2006, and subsequently on May 3, 2006, the Department received official public comment and supporting information from TRC indicating to the Department that TRC could not comply with the existing air quality permit or limits proposed in the Department's PD, some of which constituted BACT. This information was not included in the TRC permit application for permit action #3175-03 and was not analyzed by the Department in the permit application review process and, therefore, not identified in the PD issued for public comment. Because the above-cited information indicated to the Department that TRC was unable to comply with all applicable requirements, the Department's decision was to deny TRC's application for permit modification #3175-03. In a letter dated May 19, 2006, the Department denied the application and indicated that if TRC wished to pursue changes to its existing air quality permit, a complete application, including all relevant information, must be submitted to the Department for review.

On June 9, 2006, the Department received a complete application for the modification of TRC's MAQP #3175-02. Specifically, TRC requested the following changes to the permit terms/conditions related to the boiler:

- Removal of the requirement that the installed $SO_2$ control equipment meet or exceed 90% $SO_2$ reduction;
- Modification of the language specifying the $SO_2$ control technology as a dry-lime scrubber to a generic FGD system;
- Reevaluation of the BACT determined $SO_2$ emission limit(s) of 0.220 pounds per million British thermal unit (lb/MMBtu) based on a 1-hour (hr) average and 42.42 pounds per hour (lb/hr) based on a 1-hr average. TRC proposed a new $SO_2$ BACT emission limit of 0.220 lb/MMBtu based on a rolling 30-day average or 85% $SO_2$ control efficiency, whichever is less stringent. TRC also proposed removal of the $SO_2$ BACT limit expressed in lb/hr;
- Reevaluation of the BACT-determined $NO_x$ emission limits of 0.178 lb/MMBtu based on a 1-hour average and 34.32 lb/hr based on a 1-hr average. TRC proposed the installation and operation of an SNCR system and a new $NO_x$ BACT emission limit expressed in lb/MMBtu, based on a 30-day rolling average, to be determined based on achievable $NO_x$ emissions established through a statistical analysis of $NO_x$ CEMS data from the first 275 days of SNCR operation. TRC also proposed removal of the $NO_x$ BACT limit expressed in lb/hr;
- Removal of the hourly boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr;
- Removal of the boiler steam production limit of 130,000 lb/hr;
- Removal of the boiler baghouse fan flow capacity of 40,513 dry-standard cubic feet per minute (dscfm); and

- Inclusion of boiler startup and shutdown limits and operating conditions, including $SO_2$ and $NO_x$ emission limits, which would apply during defined periods of startup and shutdown only.
- Cessation of $PM_{10}$ ambient air quality monitoring requirements when TRC is not in operation.

Based on Department review of TRC's application for permit modification, the following modifications were made to TRC's permit:

$SO_2$ Modifications:

- Removal of the requirement that the installed $SO_2$ control equipment meet or exceed 90% $SO_2$ reduction. Based on the equipment specific information contained in the application for permit modification, the Department determined that this efficiency is not achievable on a steady-state basis and promotes the combustion of coal fuel with a higher sulfur concentration in order to attain a higher percent reduction without additional environmental benefit;
- Modification of the $SO_2$ control strategy language to require a generic FGD system in place of the previously specified dry-lime scrubber $SO_2$ control requirement. This modification affords TRC flexibility in choosing and installing an $SO_2$ control strategy capable of achieving the permitted BACT emission limits;
- Modification of the existing $SO_2$ BACT emission limit of 0.220 lb/MMBtu based on a 1-hr average to 0.220 lb/MMBtu based on a 30-day rolling average. Because coal sulfur content and heating value is variable, the Department determined that the 30-day rolling $SO_2$ BACT emission rate averaging time is appropriate in this case as it will provide needed flexibility for the combustion of worst-case allowable coal on a short-term basis but provide greater assurance that the affected unit will operate through combustion of typical coals for longer term normal operations. A detailed discussion of the Department's $SO_2$ BACT determination is contained in Section III, BACT Determination, of the permit analysis for MAQP#3175-04. The $SO_2$ BACT limit of 0.220 lb/MMBtu proposed under this permit action is the same as the existing $SO_2$ BACT limit under MAQP #3175-02. However, this limit is different than the $SO_2$ BACT limit proposed under the Department's PD on MAQP #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT analysis contained in Section III of the permit analysis for MAQP #3175-04, the Department determined that the limit proposed constitutes BACT in this case.
- The Department determined that a secondary lb/hr BACT emission limit based on the permitted BACT emission rate in lb/MMBtu and the boiler heat input capacity is redundant; therefore, the current permit action removes the previously BACT determined emission limit of 42.42 lb/hr. Because the permit action maintained an enforceable boiler heat input limit, the Department determined that the BACT determined emission limit in lb/MMBtu is protective of the permit analysis and constitutes BACT in this case.
- Inclusion of a boiler $SO_2$ emission limit of 155.0 lb $SO_2$/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under this permit action TRC provided a boiler startup and shutdown plan (Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown. As reported in the application for MAQP #3175-04, the required FGD $SO_2$ control equipment would be rendered ineffective until the boiler reaches an operational steam production level of approximately 70,000 pounds of steam per hour (information from Hamon Research Cottrell) or a heat input value of approximately 104 MMBtu/hr. The boiler steam load capacity is reported at 130,000 pounds of steam per hour at 192.8 MMBtu/hr. On June 7, 2006, the Department sent TRC an application deficiency letter highlighting information lacking from the application for MAQP#3175-04. In the deficiency letter, the Department asked TRC how the boiler would comply with an uncontrolled $SO_2$ emission limit of 155 lb/hr considering

that worst-case permitted allowable coal (8000 Btu/lb and 1% sulfur) combusted at a heat input rate of 104 MMBtu/hr would result in emissions exceeding this limit. In response to the Department's letter, TRC indicated that the above-cited worst-case allowable coal is theoretical and that actual coals received from the contracted coal supplier would have higher Btu content and lower sulfur concentration than the worst-case allowable coal. TRC further indicated that more typical coal would be stockpiled on-site to ensure compliance with the start-up and shutdown uncontrolled emission limit of 155 lb/hr. Assuming combustion of TRC reported typical coal at approximately 10,200 Btu/lb and 0.7% sulfur and a boiler heat input rate of 104 MMBtu/hr (effective FGD control cut-off level), uncontrolled $SO_2$ emissions from the TRC stoker boiler would not exceed 155 lb/hr. The $SO_2$ startup and shutdown emission limit of 155.0 lb $SO_2$/hr was shown through modeling to be protective of the applicable ambient air quality standard(s).

- Inclusion of a worst-case 1-hour $SO_2$ emission limit of 72.3 lb/hr based on a 1-hr averaging period applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for MAQP #3175-04, the Department determined that this action is justified, as this rate represents an 85% $SO_2$ control efficiency (guaranteed LSD/FGD control efficiency) when combusting permitted allowable worst-case coals and assuming a boiler heat input of 192.8 MMBtu/hr.
- Inclusion of an $SO_2$ continuous emissions monitoring system (CEMS) requirement. The Department determined, based on TRC's past $SO_2$ reduction performance, that an $SO_2$ CEMS is justified, especially considering the longer-term $SO_2$ emission limit averaging time (rolling 30-day average) deemed BACT in this case.

$NO_x$ Modifications:

- Inclusion of BACT-determined SNCR and FGR $NO_x$ control requirements in combination with the existing BACT requirement for OFA $NO_x$ control.
- Modification of the existing $NO_x$ BACT-determined emission rate of 0.178 lb/MMBtu based on a 1-hr average to 0.196 lb/MMBtu based on a rolling 30-day average. As specified in the permit, an emission limit of 0.28 lb/MMBtu shall apply during the initial 10-day SNCR Mapping/testing period prior to installation and operation of SNCR. An emission limit of 0.28 lb/MMBtu represents the TRC reported achievable $NO_x$ emission rate assuming the BACT-determined OFA and FGR $NO_x$ combustion controls are installed and operational during the SNCR mapping/testing period, as required by permit. Further, since the proposed SNCR $NO_x$ control strategy in combination with the existing $NO_x$ combustion controls (OFA/FGR) constitutes BACT for $NO_x$ emissions, the Department determined that an emission limit of 0.196 lb $NO_x$/MMBtu constitutes BACT, in this case. This emission limit/rate represents an additional 30% reduction (SNCR manufacturers guarantee) in $NO_x$ emissions through incorporation of SNCR, assuming the reported combustion control emission rate of 0.28 lb/MMBtu and a boiler heat input rate of 192.8 MMBtu/hr. A more detailed discussion of the $NO_x$ control and emission limit determination is contained in Section III.A.4, $NO_x$ BACT Determination, of the permit analysis for MAQP #3175-04. The Department determined that a rolling 30-day average to demonstrate compliance with the BACT-determined limit is justified. The increased averaging time will provide necessary flexibility due to reported variability in boiler operating temperature and related SNCR and combustion control efficiency. The $NO_x$ BACT limit of 0.196 lb/MMBtu proposed under MAQP #3175-04 was different than the $NO_x$ BACT limit proposed under the Department's PD on MAQP #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT analysis contained in Section III of the permit analysis for MAQP #3175-04, the Department determined that the $NO_x$ BACT limit proposed constitutes BACT in this case;
- Inclusion of a boiler $NO_x$ emission limit of 74.0 lb $NO_x$/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under MAQP #3175-04, TRC provided a boiler startup and shutdown plan describing the operational circumstances

which constitute boiler startup and shutdown. Based on information from Fuel Tech, Inc. (manufacturer of SNCR system), the SNCR unit would not be effective at a heat input rate of less than 134 MMBtu/hr. The function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of the boilers combustion system manufacturer. Based on this information, a short term limit considering no control and maintaining compliance with the applicable ambient air quality standards is necessary in order for the TRC boiler to operate within the requirements of the permit. Assuming an uncontrolled $NO_x$ emissions rate of 0.55 lb/MMBtu (AP-42, Section 1.1) and a boiler heat input rate of 134 MMBtu/hr (effective $NO_x$ control cut-off level), uncontrolled $NO_x$ emissions from the TRC stoker boiler firing subbituminous coal would be 74.0 lb/hr. Through the permit application process for MAQP #3175-04, TRC demonstrated compliance with the applicable ambient air quality standards through modeling an emissions rate of 195 lb $NO_x$/hr. Therefore, a $NO_x$ emission rate of 74 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards.

- The Department established a worst case 1-hour average $NO_x$ emission limit of 47.24 lb/hr applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for MAQP #3175-04, the Department determined that this action was justified, as this rate represents a 30% reduction (guaranteed SNCR control efficiency) from the reported worst-case $NO_x$ emissions rate of 0.35 lb/MMBtu, assuming a boiler heat input of 192.8 MMBtu/hr and required combustion controls (OFA and FGR).

Other Permit Modifications:

- Modification of the hourly boiler heat input limit of 192.8 MMBtu/hr to a limit of 192.8 MMBtu/hr based on a 24-hour average and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr. The annual heat input limit represents the reported and analyzed sustainable boiler heat input capacity of 192.8 MMBtu/hr (192.8 MMBtu/hr x 8760 hr/year). The application for MAQP #3175-04 proposed removal of the existing short-term boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual heat input limit. TRC's application for this permit modification states that because this heat input value (192.8 MMBtu/hr) was used in the calculation establishing the boiler BACT emission limits, the affected BACT limit takes into account heat input as part of the limit itself and the limit is therefore redundant. The Department disagrees with the conclusions of this argument because there is some uncertainty as to the boiler's heat input capacity and because this heat input value has been relied upon in the analysis establishing the boiler BACT limits. In the application for MAQP #3175-04 (and supporting documentation under permit action #3175-03), TRC reported that the boiler may potentially accommodate a continuous maximum firing rate of approximately 215 MMBtu/hr. However, the analysis conducted by TRC for this permit action maintains a sustainable boiler heat input capacity of 192.8 MMBtu/hr and not 215 MMBtu/hr. Therefore, the Department determined that inclusion of a short-term enforceable heat input limit is necessary to protect the analysis conducted for the proposed boiler. Further, because the boiler's heat input is directly related to BACT emissions limits, incorporation of a short-term heat input limit provides additional and practical assurance of compliance with permit limits. Finally, because the Department's analysis relied on a boiler heat input rate of 192.8 MMBtu/hr as the sustainable steady-state boiler heat input capacity the Department determined that a 24-hour (calendar-day), rather than a 1-hour, averaging period is appropriate to demonstrate compliance with the limit in this case. To provide basis for the Department's determination on the appropriate averaging period for a sustainable boiler heat input rate, the Department used indirect guidance from USEPA related specifically to federal New Source Performance Standards applicability under 40 CFR, Part 60, Subpart D. This guidance

(Applicability Determination Index Control Number 0300104) states, "the heat input rate of the steam generating unit should be based on a 24-hour full load demonstration measuring peak Btu/hr heat input after achieving steady-state conditions.";

- Removal of the steam production limit of 130,000 lb/hr. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with this permit application, the Department believes that other existing and new permit limits and conditions serve this purpose and that the steam production limit is unnecessary and actually penalizes TRC for potential increased efficiency;
- Removal of the boiler baghouse fan flow rate of 40,513 dscfm. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with MAQP #3175-04, the Department believes that other existing and new permit limits and conditions serve this purpose.
- Inclusion of boiler startup and shutdown limits and operating conditions applicable during periods of startup and shutdown only and a boiler startup and shutdown describing operational circumstances which constitute boiler startup and shutdown events. The Department believes that any startup and shutdown emissions must consider the startup and shutdown process, fuels, and controls, if applicable.
- Interim cessation of $PM_{10}$ ambient air quality monitoring requirements until initial startup of the boiler after issuance of MAQP #3175-04, and continued operations thereafter.

The PD was subject to public comment from July 6, 2006, through August 7, 2006. Based on comments received during the public comment period, the Department modified the PD as follows:

- Removal of the boiler start-up and shutdown event notification requirement contained in Section II.N.9 of the Department's PD #3175-04. The recordkeeping requirements contained in Section II.K.15 provide adequate compliance assurance related to start-up and shutdown event recordkeeping and notification.

The Department decision issued on August 21, 2006, incorporated the above-cited change. On September 3, 2006, the Citizens Awareness Network, Women's Voices for the Earth, and the Clark Fork Coalition appealed the Department's decision and requested a hearing on the appeal before the Board of Environmental Review (Board). As specified in Montana Code Annotated (MCA) 75-2-211(11)(b), the filing of a request for a hearing does not stay the Department's decision unless the Board issues a stay. Since the Board did not issue a stay in this case, the Department's decision became final on September 6, 2006. The requested hearing before the Board occurred on May 3$^{rd}$, 4$^{th}$, and 17$^{th}$ of 2007. **Permit #3175-04** replaced Permit #3175-02.

On November 21, 2007, the Department received a written notification from TRC and TRP informing the Department of TRC's intent to transfer MAQP #3175-04 from TRC to TRP. **MAQP #3175-05** replaced MAQP #3175-04.

D. Current Permit Action

On April 22, 2008, the Board of Environmental Review (Board) remanded MAQP #3175-04 to the Department to conduct a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. Pursuant to the Board order, the current permit action revises the permit to include a BACT analysis for non-steady state operation, and includes enforceable conditions in the permit to assure compliance during non-steady state operations.

On November 10, 2008, the Department received a complete submittal for proposed modifications to the permitted TRP operations. Based on the information submitted, the following changes were proposed under **MAQP #3175-06**:

- Implementation of the *Best Management Operating Procedures for Ash-Pulling Periods* and *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department, and summarized in Attachment 3 and Attachment 4 of this permit.
- Inclusion of additional information for boiler operating conditions that summarize startup and shutdown events.
- Inclusion of additional information for boiler operating conditions that summarize ash-pulling periods.
- Management of TRP's coal supply to maintain fuel sulfur levels during startup and shutdown at not more than 0.745 lb S/MMBtu.

A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-06.

$SO_2$ Modifications:

- Management of TRP's coal supply to maintain fuel sulfur levels during startup and shutdown events at not more than 0.745 lb S/MMBtu. Because coal properties can change with each coal delivery, TRP proposes to continue to obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The coal analysis shall contain, at a minimum, sulfur content, ash content, heating value (Btu/lb), and chlorine concentration and all of this will continue to be reported to the Department. TRP will use the information gathered from the coal supplier to maintain coal on-site with sulfur levels less than or equal to 0.745 lb S/MMBtu. TRP's intent is to always maintain the sulfur content at this level during steady-state and non-steady state operations; however, because coal contracts and coal properties vary, TRP requested to retain steady-state conditions in the event that they are unable to get a continuous coal contract that can meet this sulfur content. However, without further justification, such a level would be required at all times to ensure the shutdown limit, in particular would be met. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-06;
- Incorporation of enforceable boiler heat input maximum of 192.8 MMBtu/hr during startup and shutdown events based on 1-hour average. Because the Department's BACT determination relied heavily on a boiler heat input rate of 192.8 MMBtu/hr as the maximum boiler heat input, the Department determined that a 1-hour averaging period is appropriate to demonstrate compliance with the limit in this case;
- Incorporation of an enforceable boiler $SO_2$ emission limit from the TRP stoker boiler not to exceed 155 lb/hr applicable during defined startup and shutdown events (see Attachment 3). The $SO_2$ startup and shutdown emission limit of 155.0 lb $SO_2$/hr was previously shown through modeling (under MAQP #3175-04) to be protective of the applicable ambient air quality standard(s). Further, TRP proposed to maintain sulfur levels at ≤0.745 lb S/MMBtu to ensure that the uncontrolled emission limit of 155.0 lb $SO_2$/hr would be maintained during these events. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-06.
- Incorporation of the *Best Management Operational Practices for Startup and Shutdown Events* that outline equipment operations and enable the initiation of the lime injection at the earliest practicable time during startup to better control $SO_2$ emissions.
- Under the current permitting action, TRP provided a more detailed plan describing the operational circumstances which constitute boiler startup and shutdown, as well as providing the best management practices that would be conducted during these events

to limit upsets to boiler combustion. Therefore, an $SO_2$ emission rate of 155 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards.

NOx Modifications:

- Incorporation of an enforceable boiler $NO_x$ emission limit from the TRP stoker boiler not to exceed 74.0 lb/hr, applicable during defined startup and shutdown only (see *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department and summarized in Attachment 3). Based on information on file with the Department, Fuel Tech, Inc. (manufacturer of SNCR system) states that the SNCR unit would not be effective at a heat input rate of less than 134 MMBtu/hr. The function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of the boilers combustion system manufacturer. Based on this information, a short term limit considering no control and maintaining compliance with the applicable ambient air quality standards is necessary in order for the TRP boiler to operate within the requirements of the permit. Assuming an uncontrolled $NO_x$ emissions rate of 0.55 lb/MMBtu (AP-42, Section 1.1) and a boiler heat input rate of 134 MMBtu/hr (effective $NO_x$ control cut-off level), uncontrolled $NO_x$ emissions from the TRP stoker boiler firing subbituminous coal would be 74.0 lb/hr. TRP demonstrated compliance with the applicable ambient air quality standards through modeling an emissions rate of 195 lb $NO_x$/hr under MAQP #3175-04. Therefore, a $NO_x$ emission rate of 74 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-06.
- Inclusion of *Best Management Operational Practices for Startup and Shutdown Events* and *Best Management Operating Procedures for Ash-Pulling Periods* to preclude the operator from allowing unnecessary non-design air into the boiler. These documents give operators a systematic approach to follow during startup and shutdown events to ensure that equipment is operated as designed, and in the most effective manner to minimize NOx emissions.

Ash-Pulling modifications:

- Inclusion of *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department (and summarized in Attachment 4). TRP proposes to reduce intrusion of non-design air into the boiler that disrupts the combustion process by limiting the operators' entry into the boiler. Pursuant to TRP's procedures, the operator is required to inspect the grinder prior to opening the slide gate to minimize the effects of having the inspection door and the slide gate open at the same time.
- Inclusion of information submitted by TRP to show that Ash-Pulling periods occur for a maximum of one hour during every 12-hour shift (rather than two hours per 12-hour shift pursuant to information submitted under MAQP #3175-04).
- Modifications to the boiler including the installation of small ports equipped with caps to allow manual use of a rod to break up large bottom ash clinkers in addition to moving the clinker around for discharge to the clinker grinders. This modification will again limit entry to the boiler and reduce entry of fugitive air into the boiler during ash-pulling events.
- Modification to the ash removal process to eliminate the need to open both boiler doors for ash handling and removal. Previously, the procedure during ash-pulling events required that both furnace doors be opened, consequently flooding the lower furnace

with air and increasing emissions. Accordingly, TRP has modified the procedure to preclude the operator from opening the clinker grinder inspection door while the bottom ash slide gate is open. With the addition of boiler inspection ports, the detailed ash-pulling operating procedures and work practices that have been put in place to minimize non-design air into the boiler, TRP believes these modifications and improvements to the boiler will decrease the duration of these events and will result in meeting steady-state emissions limits during ash-pulling events. However, because TRP has not operated the boiler and controls with the proposed modifications and improvements; TRP proposes a ash-pulling emission's monitoring period as outlined in Attachment 5.

- Incorporation of the ash-pulling emission's monitoring period as outlined in Attachment 5. During this monitoring period, TRP will utilize the CEMs to collect NOx and $SO_2$ emissions during each ash-pulling event and the results from this monitoring will be used to: 1) verify that TRP can meet steady-state limits during ash-pulling periods for NOx and $SO_2$; and/or 2) establish new emission limits during ash-pulling periods. If TRP is unable to meet steady-state permit limits in Section II.D of MAQP #3175-06, TRP will be required to submit a permit modification to the Department.
- Incorporation of good combustion control, best management and work practices during the ash-pulling periods and corresponding monitoring period.
- Incorporation of a requirement that TRP submit the results of the monitoring period within 195 days of initial startup of the boiler or commencement of commercial operations. TRP had requested 30-days following the plant commissioning period and monitoring period to submit a report to the Department, however, the Department believes that all testing, CEMs certifications, and monitoring can be completed within 180 days and reported to the Department 15 days following completion of monitoring. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-06.
- Inclusion of a systematic approach (Attachment 4) for ash-pulling periods in addition to the above modifications will result in a decrease in the duration of the ash-pulling events from 2 hours twice per day to 1 hour twice per day.

**MAQP #3175-06** replaces MAQP #3175-05.

E. Response to Public Comments

| Person/Group Commenting | Permit Reference | Comment | Department Response |
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| Joan M. Draszt | General Comments | Concerned about the location of the facility, stack height as well as impacts to the environment. | For this particular permitting action, the Department only evaluated periods of non-steady state operation (startup and shutdown) and ash-pulling periods. All other aspects of the permit have been reviewed and approved with conditions established in MAQP #3175-04.<br><br>The Department reviewed TRP's BACT analysis and established conditions and limitations for startup, shutdown and ash-pulling periods (see Section II.B and II.C for additional information). The emission limits established in MAQP#3175-06 were shown (through previous modeling under MAQP #3175-04) to be protective of the ambient air quality standards. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of | II.D.10, II.D.11, and II.D.12 | The permit includes a new requirement that the coal burned at TRP must be less than or equal to 0.745 lb S/MMBtu (Section D.10, p 5). In addition, the general plant requirements were altered to require the | Section II.D10-II.D.12 limits the type of coal that TRP can use in their boiler and Section II.A.5 requires that TRP obtain a written coal analysis that is representative of each load of coal received from each coal |

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| the Earth | | written coal analysis include "*sulfur content (in pounds of sulfur per million British thermal units, lb S/MMBtu)*". The permit analysis (p.35) explains the importance of this limit in meeting start-up/shutdown limits for SO2.<br><br>It is unclear how TRP will "maintain" this content level – is it simply through the sole purchase of coal which meets these requirements? If, for example, given the option to purchase a load of coal with 8000 btu/lb and 1% sulfur – would they refuse it? Or will TRP attempt to mix different coals onsite to achieve this permit limit? **If so, this process (including whatever calculations and/or measurements they will use) must be spelled out in the permit, and reported to DEQ**. How else would DEQ be able to assure compliance with the permit condition?<br>Similarly – the permit still requires that coal fired at TRP also have no more than 1% sulfur content by weight (Section D. 12 p. 5). Yet there is no longer a requirement that sulfur content (in % by weight units) be included in the written coal analysis. How will DEQ assure compliance with this permit condition without that information? **We ask that that sulfur content in % by weight units be re-added to the required information in the written coal analysis.** | supplier. This coal analysis shall contain, at a minimum, sulfur content (in pounds of sulfur per million British thermal units, lb S/MMBtu), ash content, heating value (Btu/lb), and chlorine concentration.<br><br>The current permit action limits the maximum sulfur content at 1% and the minimum heating value at 8000 Btu/lb, and the Department added the sulfur content (in lb S/MMBtu). The Department removed the percent sulfur (by weight) requirement in this permit action because it is redundant. The percent sulfur (by weight) is included in the calculation to determine sulfur content in lb S/MMBtu. For example if the heat content of coal is 10,200 Btu/lb and the sulfur content of coal is 0.76% (by weight) the resulting sulfur content would be (0.0076 Sulfur/10,200 Btu/lb) equal to 0.000000745 lb S/Btu.<br><br>Although the sulfur content (in lb S/MMBtu) inherently includes percent sulfur (by weight), the Department has added the requirement to report percent sulfur content (by weight) to Section II.A.5 and Section II.L.2. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Section IV of the Permit Analysis, Emission Inventory | We noticed in the permit analysis that the annual emissions inventory chart has been removed. (section IV p. 44) This makes it difficult to understand the big picture of how these permit modifications affect overall emissions coming from this plant. We are especially concerned given our belief that this plant is a PSD major source, given their potential to emit. **We would appreciate if DEQ could calculate the overall emissions,which would include the changes in this permit and include them in the permit analysis. This should include the worst case emissions if TRP utilizes the 90 day allowance for higher limits during ash pulling (if they cannot meet steady-state emissions).** | The Board of Environmental Review (Board) remanded MAQP #3175-04 to the Department to conduct a thorough, top-down supplemental Best Available Control Technology (BACT) analysis for periods of non-steady state operation. The Department only evaluated those sections of the permit that relate to startup, shutdown and ash-pulling procedures with respect to NOx and $SO_2$.<br><br>The Department previously determined that TRP is not a PSD source, and this permit action will not change the status.<br><br>The Department added the summary emission table that was previously developed in MAQP#3175-04 to Section IV of this permit action. However, the Department did not include startup, shutdown or ash-pulling emissions in this table. The emissions for the boiler were based on operating 8760 hours per year even though there will be times that the boiler is down for maintenance, troubleshooting, or general plant maintenance, etc. If the Department included emissions for startup and shutdown, or ash-pulling events, the emissions would potentially be double counted and inaccurate.<br>Emission limits for ash-pulling periods have |

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| | | | been set at steady state limits (established under MAQP #3175-04).<br><br>In order to ensure that TRP can meet steady-state limits, the Department added a monitoring period for data collection during these events. MAQP #3175-06 also requires TRP to respond to the Department within 15 days following completion of the monitoring period but no later than 195 days after initial startup of the boiler. At that time, TRP must either submit a report to the Department verifying that they can meet steady-state $NO_x$ and $SO_2$ emission limits (II.D.14.a. and II.D.14.c.); or TRP must submit a permit application to modify $NO_x$ and $SO_2$ emission limits during ash-pulling periods.<br><br>In the event that TRP submits an application for a permit modification (required to be submitted and approved within 90 days following the 180 day testing period after the initial startup of the boiler or commencement of commercial operations) because they are unable to meet steady-state limits during ash-pulling periods, the Department will evaluate the change in emission limits during ash-pulling periods and will include additional calculations that reflect any change in emissions. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Section III or the Permit Analysis | In the permit analysis (p.38), an explanation is given for eliminating automatic ash-pulling from consideration as a control technology, despite its feasibility.<br><br>We question this decision for several reasons. 1) It is unclear form the information presented here why automatic ash-pulling (which appears to be very common for boilers these days) would not result in less non-design air flowing into the boiler than manual ash-pulling. **This claim should be verified by DEQ with vendors of this equipment.** 2) TRP further claims that NOx emissions would not decrease. However, no mention is made of whether SO2, or particulate emissions would decrease from automatic ash-pulling. **DEQ should consider if automatic ash-pulling may benefit emissions of these other key pollutants and verify the claim that NOx emissions would not decrease.** 3) TRP claims that the boiler operation relies heavily on visual observation to identify the presence of ash clinker or other problems. This problem appears to be remedied by the combustion control measures they are willing to introduce, namely the small ports added to the boiler. Presumably these ports should suffice for most situations, with only the occasional need to open the gates if a larger problem is detected. If large ash clinker is a routinely common problem, there should probably be additional | The Department determined that the addition of an automatic ash-pulling system would not provide additional benefit to reduce the NOx emissions. Both automatic and manual ash-pulling processes associated with stoker boilers result in non-design air flowing into the boiler thereby disrupting the combustion process.<br><br>NOx emissions that result are attributed to a loss of control over the air flow and would result with automatic or manual ash-pulling. The Department determined that both processes ultimately would have the same result (due to the intrusion of fugitive air). However, boiler modifications proposed by TRP should limit the amount of air into the boiler.<br><br>Particulate emissions were not evaluated or required to be evaluated for this permitting action. $SO_2$ emissions at TRP are not expected to increase during ash-pulling activities. However, both NOx and $SO_2$ emissions will be monitored during the ash-pulling periods to verify this (see Attachment 5) and all results will be reported to the Department.<br><br>The primary problem with ash-pulling periods is attributed to non-design air flow into the boiler and temperature fluctuations and these issues should be addressed with the proposed boiler modifications. |

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| | | combustion control measures put in place to reduce the occurrence of this problem. **DEQ should reconsider the use of automatic ash-pulling as BACT in this permit.** | In addition, TRP believes that the boiler load will never fall below the capabilities of the air pollution control equipment during ash-pulling periods as a result of the boiler modification. The Department will closely monitor this facility for compliance. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Section II.C | We appreciate that DEQ has implemented a 30 day intensive monitoring period to address the ash-pulling, (rather than the 60 day period requested by TRP.) We also appreciate that this 30 day period must be completed within the "shakedown period" and not subsequent to this time.<br><br>While the monitoring period specifically requires data on SO2 and NOx we are also concerned, about the potential for PM-10 and opacity emissions from ash-pulling as well. **We ask that the results of the COMS and ambient PM-10 monitors during ash-pulling events also be included in the data to be reported to DEQ.** | The Board's decision to remand MAQP #3175-04 stated that the Department must conduct a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. The non-steady state BACT determination must also include an analysis of the impact of the new BACT standards on overall BACT determined emission limits for NOx and $SO_2$ and whether the overall BACT limits and averaging time should be adjusted through a new BACT analysis.<br><br>Re-evaluation of $PM_{10}$ emissions and opacity were not within the scope of the Board's remand. However, TRP would be required to submit all COMS/CEMS reports (see Section II.L) to the Department. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Attachment 5 | Also, it is unclear from the Monitoring Period procedures (Attachment 5) if the time it takes to conduct ash-pulling will be monitored and recorded. In the permit analysis, it states (p.38):<br><br>Duration and Frequency: Modification to the boiler in addition to the best management practices should decrease the duration of the ash-pulling events. TRP has proposed 1-hour ash pulling events twice per day rather than 2-hours twice per day.<br><br>And in fact, DEQ has calculated potential emissions based on ash-pulling events occurring for no more than 2 hrs each day. However, it remains to be seen if an ash-pulling event can in fact be completed in the one hour timeframe with the BMPs in place, or if this is merely an optimistic assumption. It is also unclear if TRP will need to conduct more than two ash-pulling events in a day, as there is no limit on the number of ash-pulling events allowed. We ask that the start and stop times for ash-pulling be recorded and reported to DEQ to verify that the one-hour timeframe twice per day can be achieved. This is clearly important information for DEQ to have if modified permit limits might eventually be applied for.<br><br>Also, if TRP cannot meet steady-state permit limits, DEQ has allowed a 90 day period in which to apply for a permit modification, during which the permit limits are set at their non-steady-state maximums. If TRP needs to use this 90 day period, it is important for TRP to record start and stop times for ash-pulling events to assure | The Department has added this requirement to Attachment 5. TRP will be required to record the duration and frequency of all ash-pulling periods. |

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| | | compliance during steady-state conditions. Otherwise, any violation of SO2 or NOx steady state limits (that actually occurs during normal operation) during this 90 day period could be inappropriately attributed to an ash-pulling event. DEQ must require reporting of start and stop times for ash-pulling events in order to assure compliance during normal operation. | |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | General Comment | We hold firm in our belief that the TRP Facility qualifies as a "major stationary source," and should be bound by the more stringent standards associated with the designation. Were potential emissions from the plant substantial enough to constitute a "major stationary source" of pollutants under ARM §§ 17.8.801 et seq., then the TRP Facility would be subject to the Prevention of Significant Deterioration (PSD) requirements set forth in Montana air quality regulations. A Hearings Examiner has denied our attempt to have the "major stationary source" claim included in the record for consideration. We believe that decision to be inconsistent with the controlling law, resulting in a less than thorough review, if not skewed analysis, of this proposal. We are prepared to ask the Montana Supreme Court to review the issue, and based on case law, firmly believe that review will result in the "major stationary source" claim being included in the Department's examination. | This permit action is being conducted by the Department pursuant to an order of the Board remanding Section II.B. of MAQP #3175-04, "Boiler Startup and Shutdown Operations," to the Department. The Department previously determined that TRP's application for MAQP #3175-04 was not subject to PSD permitting requirements. In the contested case that led to the remand, the Board denied the Petitioners' (Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth) motion to amend their hearing request affidavit to add a new claim that the application for MAQP #3175-04 should have been processed pursuant to PSD permitting requirements. On December 22, 2008, in the judicial review proceeding initiated by the Petitioners, the district court issued an order denying the Petitioners' motion for summary judgment, affirming the February 2, 2007, order of the hearing officer denying the Petitioner's motion for leave to file an amended affidavit, and affirming the June 11, 2008, final order of the Board.<br><br>The scope of the Board's remand of Section II.B of MAQP #3175-04 did not include reassessment of the Department's determination that the application for MAQP #3175-04 was not subject to PSD permitting requirements, and this permitting action will not change the minor source status of the facility and its emission units.<br><br>This permitting action included only review of emissions during startup, shutdown, and ash pulling. Pursuant to the Board's order remanding Section II.B of MAQP #3175-04, the Department conducted a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. The non-steady state BACT determination also included an analysis of the impact of the new BACT standards on overall BACT determined emission limits for NOx and SO2 and whether the overall BACT limits and averaging times should be adjusted through a new BACT analysis. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Environ-mental Assessment | The Environmental Assessment (EA) completed in association with Permit 3175-06 provides a compilation of potential economic and social impacts of the TRP Facility. Section L addresses cumulative and secondary impacts of the facility, | The Environmental Assessment for this permit action is commensurate with the scope of the Board's remand and the permitting action, and, therefore, addresses only the impacts that might result during startup, shutdown and ash-pulling periods. |

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| | | stating:<br><br>"Overall, cumulative and secondary impacts from the proposed permit modification on the economic and social resources of the human environment in the immediate area would be minor due to the fact that the predominant use of the surrounding area would not change as a result of the proposed project." (Permit 3175-06 p.54).<br><br>We believe this analysis lacks the universally accepted acknowledgment that coal-fired energy production facilities are one of the leading contributors to climate change. By extension, climate change will have far-reaching and unavoidable economic, social and environmental impacts. This is a consensus belief held by scientific authorities the world round. The option left for our society, Montana included, is to mitigate the inevitable impacts of climate change by reducing all future greenhouse gas contributions as significantly as possible. Governor Schweitzer and Director Opper are in agreement on this issue. Permitting outdated, technologically inferior coal-fired energy production facilities runs antithetical to this belief. We urge the Department to insert this overarching consideration into its analysis of this and other proposed coal-fired energy production facilities. | The Department has addressed other potential impacts of the facility under MAQP #3175-04 and MAQP #3175-01. |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | Section II | We have heard from DEQ that you feel the longer averaging times are reasonable as it allows greater flexibility for TRP's operations and do not matter in the long run as the monthly and annual emissions would be the same or only slightly higher than the previous permit. We disagree with this assumption that there will not be an impact on air quality. The greater flexibility (even with the changes asked for above) would still allow for short term emission spikes which would not trigger a violation. The concern is obviously greater with the 30 day averaging period for $SO_2$ and NOx - as the longer the averaging period the greater potential for variation in emissions. We are concerned about the potential of these emission spikes from a public health standpoint. While environmental law is not yet sophisticated enough to accommodate new scientific information quickly, we believe it is important to bring to the DEQ's attention. Specifically, there have been a number of recent scientific studies looking at short term increases in pollutant levels and their effects on health. Serious health effects, such as increases in hospital admissions for stroke and cardiovascular diseases, have been associated with small increases in ambient pollutant levels of PM10, SO2 and NOx - even those increases | This comment appears to relate to the rolling 30-day averaging periods determined to constitute BACT for the lb/MMBtu NOx and $SO_2$ emission limits in MAQP #3175-04. As stated in the introduction to the Petitioners' present comment, this is a reiteration of a comment that the Petitioners submitted regarding MAQP #3175-04. It also is a reiteration of comments the Petitioners included in Paragraphs 5 and 6 of their affidavit filed in support of their request for a contested case hearing on MAQP #3175-04. However, in that affidavit, the Petitioners did not claim that the averaging periods violated BACT requirements or any other applicable air quality permitting requirement, and, as noted in Paragraph 19 of the Board's final order in the contested case, the Petitioners ultimately waived their arguments regarding the rolling 30-day averaging periods, and this issue was not addressed at the contested case hearing or in the Board's remand order. Further, the Department's BACT determination for MAQP #3175-04 also included lb/hr limits for NOx and $SO_2$ as well as PM-10, and those limits remain in the permit.<br><br>For this particular permitting action, the Department placed hourly limits on startup |

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| | | that last no more than a single day. Naturally, the vulnerable sectors of the population (very young children, the elderly, those with already compromised health) are the most susceptible to these small changes in ambient pollution. We are concerned that the flexibility given TRP is being given at the risk of the health of these vulnerable populations without an appropriate analysis of these effects. We ask DEQ to conduct an analysis to assure the public that short-term spikes in emissions of these pollutants made possible by the longer averaging times will not significantly affect public health. | and shutdown events.<br><br>For ash-pulling periods, the facility will be required to meet the steady-state limits that were approved under MAQP#3175-04. Additionally, the modeling results for this project have previously demonstrated (under MAQP #3175-04) compliance with the Montana Ambient Air Quality Standards (MAAQS)/NAAQS. |
| Clark Fork Coalition, Community Awareness Network, and<br>Women's Voices of the Earth | Section II.K | We have concerns about the 180 day "shakedown periods" allowed in this permit in Section II.K. It appears in Section II.K that this permit allows TRP a second 180-day shakedown period following the issuance of permit 3175-06. We are very concerned about this given TRP's use of their shakedown periods after issuance of 3175-02, in which the required compliance testing was done only at the very end of the 180 day period. In addition, correspondence from TRP to DEQ from October 21, 2005 seems to indicate that TRP was/is under the impression that no permit conditions apply to the facility during the first 180 days of operation. This misperception must be clarified in the permit. The result previously was that there was little to no information about compliance for the first 6 months of operation in 2005. This situation "allowed" unlawful and unhealthful levels of emissions to be imposed on the neighbors to this facility for 6 months before they could be stopped. For example, TRP's reported emissions of SO2 from the stack test were 150.15 lb/hr - this is just barely under the calculated effects-based limit of 155 lb/hr which is the upper limit to prevent a violation of the NAAQS for SO2. Although there is no other data that was collected, it is not unreasonable to assume (given the fluctuations in boiler operations, variations in coal composition and the general tendency to operate "with your best foot forward" during testing) that at some point or points in that first six months, TRP did have emissions greater than 155 lb/hr causing a violation the ambient standards for SO2. This is unacceptable for the health of the community and DEQ must act to prevent this from occurring again. We understand the need for a shakedown period for a new plant - and in this case, perhaps, a shakedown period may be necessary for fine tuning of the new SNCR equipment and the new SO2 CEMS. However, given that TRP has already had a 180 day shakedown period to work out the kinks for most of the rest of its boiler operations, we | All emission source testing, sampling and data collection, recording, analysis, and transmittal must be performed as specified in the Montana Source Test Protocol and Procedures Manual. In almost all cases, the Department allows 180 days to complete the necessary testing pursuant to 40 CFR 60, Subpart A. Prior to conducting the required performance tests, the facility must install and calibrate equipment, ensure the system is operating properly, and establish testing protocol. In addition, the facility must submit to the Department at least 30 days prior to any performance test, testing protocol for Department review and approval. This not only allows the Department time to review the protocol and comment on any discrepancies, but it also allows the Department an opportunity to be present during the test.<br><br>In this case, the Department only allowed 150 days to have the plant in full operation (including completed performance tests, CEMs certification, etc) because TRP is required to collect 30 days of certified data (under Section II.C.2 and Attachment 5 of this permit) following the "shakedown period".<br><br>With respect to potential future emission exceedances, the Department understands that TRP historically had problems with its operation. The Department has taken appropriate enforcement action for past violations and the Department will closely monitor TRP's compliance with this permit. |

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| | | ask that DEQ alter Section II.K to allow for no longer than a 60 day shakedown period before compliance testing be required. | |
| Clark Fork Coalition, Community Awareness Network, and Women's Voices of the Earth | | We remain very concerned about the impacts of PM-10 emissions from TRP on the health of the community. PM-10 stack testing conducted previously indicated that TRP's emissions are close to (although they didn't exceed) their permit limits. (Specifically they reported emissions of 4.67 lb/hr, which is nearly 80% of their permit limit of 5.90 lb/hr.) Modeling conducted for the previous permit shows that the ambient concentration of particulate matter in the air may increase from 30 ug/m3 (micrograms per cubic meter) to 136 ug/m3 - and increase of 350%! This brings the facility to 91% of the NAAQS standard. As discussed in previous comments (see WVE's comments on 3175-01, 10/25/04) we have little faith in the ability of the PM NAAQS standards to adequately protect health. Thus we are very concerned that existing permit conditions for PM are not stringent enough for the community of Thompson Falls. Therefore the correct and consistent operation of the PM-10 ambient monitor is absolutely crucial to ensuring PM-10 emissions are controlled appropriately. We disagree with the change in 3175-04 (Section II.M) which allows TRP to cease operations of the monitor until the initial date of boiler startup. TRP's ambient monitoring plan has not changed. It requires an ambient monitor to be operating in an approved location at all times. TRP has a history of violating this monitoring plan, specifically, they did not operate the monitor for the first three months of boiler operation and places the monitor in an unapproved and inappropriate location. It seems clear from this past experience that TRP does not deserve the benefit of the doubt that they will "get it right" this time. The community needs to know that the monitor is in the correct place and fully operational BEFORE the boiler is started up. Unlike a stack test, the ambient monitor can be operated and tested regardless whether the boiler is operating or not. By allowing TRP to cease operation until the day of startup practically ensures that any kinks in the monitor's data collection will not be worked out ahead of time, meaning the first few days or weeks of data will not be valid. It also ensures that DEQ will not be able to inspect and approve the location of the monitor before boiler startup. Again, TRP has not earned the right to be trusted that this will be done appropriately, as they failed the first time. We ask that DEQ modify Section II.N to require the operation of the ambient monitor to begin at least two weeks before initial startup of the boiler. | As stated in the introduction to the Petitioners' present comment, this is a reiteration of a comment that the Petitioners submitted regarding MAQP #3175-04. It also is a reiteration of comments the Petitioners included in Paragraphs 22 and 23 of their affidavit filed in support of their request for a contested case hearing on MAQP #3175-04. However, in that affidavit, the Petitioners did not claim that the permit conditions related to PM violated any applicable air quality permitting requirements. As noted in Paragraph 19 of the Board's final order in the contested case, the Petitioners ultimately waived their arguments regarding PM conditions in the permit, and this issue was not addressed at the contested case hearing or in the Board's remand order.<br><br>This permit action included only review of startup, shutdown, and ash pulling emissions, and did not include reassessment of $PM_{10}$ ambient monitoring requirements in the permit. |

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| | | Again, since the data from this monitor is so crucial to assuring the protection of public health, we would like to ask if the public availability of the data from the ambient PM-10 monitor could be improved. Can this data be made available as soon as possible to the public, either by website or through an interested parties list? | |
| Sander County Board of Commissioners<br><br>Greg Hinkle, Senator Elect SD7<br><br>Representative Pat Ingrahm | General Comments | Comments in support of the project and to request final Department approval of this project. | All three requested information on this project and all provided support for issuance of TRPs air quality permit.<br><br>The Department responded under separate cover as to why this project has been delayed and unable to proceed. |
| Kim Hofland | General Comments | Comments received by the Department have been summarized as follows:<br>-concerned with the number of permits the Department has issued and the cost associated with drafting permits;<br>-questioned the stack height of the facility;<br>-concerned about the location of TRP;<br>-concerned about allowing the facility to construct without public participation;<br>-concerned about synchronizing state permits and problems with water rights;<br>-original design enclosed coal piles but they are not covered; and<br>-concerned about dust and noise pollution. | Note: These comments were received after the comment period ended.<br><br>The Administrative Rules of Montana requires that any modification to an existing permit/facility must be reviewed and approved by the Department. The Department reviews each application for completeness and then issues a permit which is available for a public comment period and an appeal period. Administrative changes are also reviewed by the Department, but do not have a public comment period. Administrative amendments usually involve a name change or clarifications and do not result in an increase in emissions. Each time the Department issues a permit as a result of an administrative change or a permit modification, the permit number remains and the extension is increased by one. This helps the Department to track changes.<br><br>For this particular permitting action, the Department only evaluated periods of non-steady state operation (startup and shutdown) and ash-pulling periods. All other aspects of the permit (such as coal piles, dust and noise pollution and stack height) were reviewed and approved with conditions established in MAQP #3175-04.<br><br>Unfortunately, the review time for other State permits involving facilities such as TRP usually never coincide. All State Agencies operate on different timelines, as well as different rules and regulations. The rules that govern the air quality permitting process require that the Department issue a final permit within 75-90 days of a complete application. |

F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct test, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

   TRP shall conduct initial source testing for $NO_x$, CO, $SO_2$, PM/$PM_{10}$, and HCl within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test monitoring compliance with the applicable boiler emission limits, TRP shall conduct additional source testing as indicated below, or according to another Department approved testing/monitoring schedule:

   - $NO_x$, CO, and $SO_2$ on an every 2-year basis and/or CEMS, as applicable;
   - Opacity and PM/$PM_{10}$ on an annual basis, and/or COMS; and
   - HCl on an every 4-year basis.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   TRP shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring.
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide.
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide.
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide.
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone.
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter.
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility.
8. ARM 17.8.223 Ambient Air Quality Standard for $PM_{10}$.

TRP shall maintain compliance with all applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of 20% for all fugitive emission sources and that reasonable precautions must be taken to control emissions of airborne particulate matter. (2) Under this rule, TRP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid or gaseous fuel in excess of the amount set forth in this section. TRP has proposed a limit less than that required in this section. Permit #3175-06 contains a federally enforceable permit limit for coal sulfur content.

6. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). TRP is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts:

   40 CFR 60, Subpart A, General Provisions. This subpart applies to the boiler because the boiler is an affected unit under 40 CFR 60, Subpart Db.

   40 CFR 60, Subpart Db, Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units. This subpart applies to the boiler because the boiler meets the definition of an affected source under this Subpart.

7. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as applicable. TRP is not a major source of Hazardous Air Pollutants (HAPs); therefore, TRP is not currently subject to any Maximum Achievable Control Technology (MACT) standards under this rule.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. TRP must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the new or modified stack for TRP is below the allowable 65-meter GEP stack height.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. TRP was not required to submit an MAQP application fee because the current MAQP action was a remand ordered by the Board.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. TRP has a PTE greater than 25 tons per year of PM, $PM_{10}$, $NO_x$, CO, $SO_2$, and VOCs; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. TRP submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. TRP was not required to submit an affidavit of public notice because the current permitting action was a remand ordered by the Board.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of the permit analysis to this permit.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving TRP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit

limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

   This facility is not a major stationary source since this facility is not a listed source and the facility's potential to emit is below 250 tons per year of any pollutant (excluding fugitive emissions).

   Because the project has a symbiotic relationship with TRL the Department reviewed whether or not the two sources should be considered a single source under the requirements of NSR. If TRP and TRL were considered a single source, the source would be subject to the requirements of the NSR/PSD program. In order for two separate facilities to be considered a single source the following three criteria must be met:

   - The facilities must be under common control and ownership;
   - The facilities must be located on contiguous and adjacent properties; and
   - The facilities must share the same SIC code.

   While TRP and TRL are located on contiguous and adjacent properties, the companies are owned by separate entities, do not have common control, and have separate SIC codes. Therefore, TRP and TRL are considered separate sources under the requirements of NSR/PSD.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE > 100 ton/year of any pollutant; or

   b. PTE > 10 ton/year of any one HAP, PTE > 25 ton/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. Sources with the PTE > 70 ton/year of $PM_{10}$ in a serious $PM_{10}$ nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Montana Air Quality Permit #3175-05 for TRP, the following conclusions were made:

   a. The facility's PTE is greater than 100 ton/year for $NO_x$, CO, and $SO_2$.

   b. The facility's permitted allowable PTE is less than 10 ton/year for any individual HAP and less than 25 ton/year of all HAPs.

   c. This source is not located in a serious $PM_{10}$ nonattainment area.

   d. This facility is subject to 40 CFR Part 60, Subpart A and Db.

   e. This facility is not subject to any current NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

   g. This source is not an EPA designated Title V source.

   Based on these facts, the Department determined that TRP is a major source of emissions as defined under Title V. Operating Permit #OP3175-02 was issued to TRP final and effective on February 12, 2008.

III. BACT Determination

A BACT determination is required for each new or modified source of emissions. TRP shall install on the new or modified source of emissions the maximum air pollution control capability that is technically practicable and economically feasible, except that the BACT shall be utilized.

Under the current permit action, TRP provided a top-down BACT analysis for periods of non-steady state operation in an effort to meet the requirements of the April 22, 2008, Board Order remanding MAQP #317-04 to the Department. The top-down BACT analysis below is pursuant to the Order issued by the Board in the matter of contested case number BER 2006-18 AQ. The following provides a summary of the BACT analysis submitted by TRP in the application for permit modification and the Department's BACT determination based on the information provided.

In this case, since part of the proposed project is the modification of an existing and previously permitted coal and wood-waste fired boiler, the Department determined that the analysis of potentially inherently lower polluting processes including, but not limited to, integrated gasification combined cycle (IGCC) and circulating fluidized bed (CFB) coal combustion technologies, are not appropriate because these would be considered a redefinition of the source.

A BACT analysis was submitted by TRC in MAQP #3175-00 and expanded upon through MAQP #3175-01 and #3175-04, and permit application #3175-03. The Department did not re-evaluate all available control technologies for $NO_x$ and $SO_2$ for non-steady state when 1) controls had already been evaluated and eliminated by the Department in previous BACT analysis; and 2) would not provide additional emission reductions for $NO_x$ and $SO_2$ during non-steady state operation.

The Board's decision to remand MAQP #3175-04 stated that the Department must conduct a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. The non-steady state BACT determination must also include an analysis of the impact of the new BACT standards on overall BACT determined emission limits for $NO_x$ and $SO_2$ and whether the overall BACT limits and averaging time should be adjusted through a new BACT analysis.

**NOx BACT Analysis for Startup and Shutdown Events**

**Step 1 - Identify All Control Technologies**

The first step in a top-down BACT analysis is to identify all "available" control options for the pollutant and emission unit in question. Available control options as defined by the New Source Review Workshop Manual, October, 1990 draft (NSR Manual) include those air pollution control technologies or techniques with a practical potential for application to each regulated pollutant being evaluated.

As an introduction to the detailed discussion of $NO_X$ control technologies, it is useful first to review what is considered startup and shutdown for the Babcock and Wilcox spreader stoker boiler (Boiler). A startup event takes the facility from a non-operational condition to a steady-state electrical load condition. During the startup process, TRP goes through a number of steps for a cold start or a warm re-start until the system is brought up to a steady-state load. A shutdown event takes the boiler from a steady-state electrical load condition to a non-operational condition, or from a mid startup condition to a non-operating condition. TRP anticipates one startup period of 48 hours plus one shutdown period of 8 hours during each quarter for a total of 4 startups and 4 shutdowns per year. The process of startup and shutdown is further discussed in Attachment 3 and the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

$NO_X$, refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide ($NO_2$), and trace quantities of other species. $NO_X$ emissions from combustion processes are typically more than 95% NO with the remainder being primarily $NO_2$. Once the flue gas leaves the stack, however, most of the NO is oxidized in the atmosphere to create $NO_2$ in a process that can take several hours to complete. The extent to which the NO is oxidized to $NO_2$ is a function of a number of meteorological variables, including ambient ozone levels.

The two primary mechanisms for formation of $NO_X$ are thermal $NO_X$ and fuel $NO_X$. Thermal $NO_X$ refers to the $NO_X$ formed through high-temperature oxidation of the nitrogen found in the combustion air. The primary factors contributing to an increased thermal $NO_X$ formation rate are the same factors contributing to complete combustion of fuel: combustion temperature, residence time, and mixing or turbulence. Regardless of the fuel being combusted, thermal $NO_X$ generally becomes a significant factor at combustion temperatures of approximately 2,200ºF, with exponential increases in formation rate at higher temperatures. For fuels with relatively low nitrogen content, such as natural gas, thermal $NO_X$ is the primary $NO_X$ formation mechanism.

Fuel $NO_X$ refers to the $NO_X$ formed by the conversion of fuel-bound nitrogen to $NO_X$ during combustion. Fuel $NO_X$ accounts for a major portion of the total $NO_X$ emissions from the combustion of nitrogen containing fuels, such as coal and wood waste. A variety of factors, including the combustion temperature, fuel-air stoichiometric ratio, and coal/wood waste characteristics (moisture, volatile matter, and nitrogen) are believed to contribute to the fuel $NO_X$ formation mechanism.

Stoker type boilers are the most common type of coal/wood waste firing systems in the United States. The reduction of $NO_x$ emissions from stoker boilers can be accomplished with combustion modification and flue gas treatment techniques or a combination of these. The application of a specific technique will depend on the type of boiler, the characteristic of its primary fuel, purpose for control, and method of firing. Many of the controls available have limited application for startup and shutdown events, and certain boilers have little or no flexibility for modification of combustion conditions because of method of firing, size, physical configuration, or operating practices.

The US EPA RACT/BACT/LAER Clearinghouse Database (RBLC), California's BACT database (CARB), Bay Area Air Quality Management District (BAAQMD) BACT Guidelines, and South Coast Air Quality Management District (SCAQMD) BACT Determinations were reviewed to identify the possible types of $NO_x$ controls permitted for coal/wood-fired boilers during startup and shutdown events.[1]

Review of these databases for BACT during non-steady state operation identified only startup and shutdown conditions for a fluidized bed type boiler in Illinois that utilized selective non-catalytic reduction (SNCR). Because of the fundamental differences between the stoker boilers and fluidized bed type boilers, and the fact that TRP's boiler and the fluidized bed type boiler both utilize SNCR for control of $NO_x$, specific emission limits for the fluidized bed type boiler are not applicable in this instance and was not further evaluated.

Based on review of available literature, and without regard to feasibility, TRP evaluated the following control options for $NO_x$ emissions from the boiler during startup and shutdown events:

- Flue gas recirculation;
- Combustion Controls;
- Repowering;
- Low $NO_x$ Burners;
- Reburn;
- Selective non-catalytic reduction; and
- Selective Catalytic reduction.

SNCR is already being used by TRP to control NOx emissions from the boiler along with simultaneous application of flue gas recirculation and overfire air (staged combustion, discussed above). Therefore, the Department has provided limited additional information on these control technologies. Because some of the existing control technologies are only partially effective at removing $NO_x$ during startup and shutdown, this analysis will only discuss applicability during these events.

Flue Gas Recirculation

Flue gas recirculation (FGR) for NOx control includes gas recirculation into the furnace or into the burner. In this technology 20-30% of the flue gas is re-circulated and mixed with the combustion air. The resulting dilution in the flame decreases the temperature and availability of oxygen therefore reducing thermal NOx formation. When flue gas recirculation into the burner is used in low NOx burners, the flue gas is usually re-circulated subject to the operational constraints of flame stability and impingement, as well as boiler vibration.

Flue gas recirculation alone in coal-fired boilers achieves a low NOx reduction efficiency (<20%). This is because the ratio of thermal-NOx to total NOx emissions is relatively low in coal-fired plants. The technique is being used on coal-fired units in combination with other primary measures for NOx control. FGR is already being utilized by TRP for NOx control.

Combustion Controls

Thermal $NO_X$ can be reduced by minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and through good combustion design. The first technique is often referred to as low excess air (LEA) and can be attained by optimizing the operation for minimum excess air without excessive increase in combustible emissions (i.e., CO and VOC). The effect of lower oxygen concentration on $NO_X$ is partially offset by some increase in thermal $NO_X$ because of higher peak temperatures with lower gas volume.

[1] Sierra Research, BACT Analysis for TRP, May 30, 2008

Another type of combustion control, air staging, reduces flame temperature and oxygen availability by minimizing the amount of combustion air that is introduced in the primary burning zone, and introduces the final amount of combustion air above the primary combustion zone. Staged combustion air can be accomplished by several means, but for stoker boilers staged air combustion is an inherent part of the design. For stoker boilers, air staging begins by introducing the coal/wood waste on a grate, having air blown from below the grate up through the burning coal/wood, and by introduction of over-fire air (OFA) above the grate for final burnout of combustibles. By limiting the amount of air introduced below the grate, the conversion of nitrogen to $NO_X$ can be minimized due to the resulting lowered flame temperatures. Final burnout air is introduced through OFA ports above the grate. A third technique involves having a larger furnace area to lower the peak heat release temperature in the furnace and to allow sufficient residence time for final burnout of combustibles.

Fuel $NO_X$ can be reduced by suppressing the amount of air required for complete combustion in the primary combustion zone (on the grate for stoker boilers), and by using low nitrogen fuels. However, coal is not generally characterized by its nitrogen content and the stoker boiler already inherently operates with lower oxygen levels at the grate and higher oxygen levels in the furnace. For overfeed, coal/wood-fired, stoker boilers, the combustion control techniques discussed above are collectively referred to as good combustion practice, good combustion design and operation, or combustion controls. In this document these types of controls are referred to as combustion controls (CC).

Because startup and shutdowns periods are generally required for operation of the TRP boiler, TRP provided additional ways to assist with CC to minimize the frequency of these events and $NO_x$ emissions by ensuring that plant operators follow the systematic approach during startup and shutdown events. This approach will limit the amount of excess air supplied to the boiler. System operating specifics that assist with CC include: electrical and mechanical line-ups, equipment operating prerequisites, operator precautions, and a step by step approach to limit the amount of emergency and abnormal operating conditions. TRPs systematic approach to management of air and fuel flow, and the initiation of the reagent injection at the earliest possible point in the startup process is outlined in Attachment 3 and the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

Repowering

As generally defined in section 402 of the Clean Air Act, the term "repowering" means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990.

Low $NO_x$ Burners

Low $NO_x$ Burners (LNB) limits $NO_x$ formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone. The LNB is designed to create a reduction of oxygen in the combustion zone which limits the fuel $NO_x$ formation, and reducing the residence time of the peak flame temperature. The emission control strategy for a LNB achieves NOx reduction by including staged air, staged fuel and flue gas recirculation (FGR).

Reburn

Reburn is accomplished by retrofitting the boiler with an additional burner above the main combustion zone creating a reburn zone. In a reburn configured boiler, the heat input to the main combustion zone is significantly reduced and reburn fuels are injected above the main combustion zone creating a fuel-rich and oxygen-deficient environment that reduces the $NO_x$ formation by converting $NO_x$ to nitrogen and water. According to TRP, the reburn zone must be maintained above 1800 °F in order for the reburn fuel to decompose or pyrolize. Both the main combustion zone and the reburn zone require a large enough area to provide for sufficient residence time to assure complete combustion. Otherwise, unreacted carbon monoxide in the flue gas could cause corrosion in the boiler convection tubes; and unburned carbon in the fly ash could increase the potential for fires in the particulate control device[2,3,4].

Reburn can be used on many different boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. Reburn fuels replace up to 5-25% of the total boiler heat load. The nitrogen content in natural gas and oils are inherently lower than coal. However, the application and effectiveness are site-specific because boilers are generally designed to achieve specific steam conditions and capacity which would be altered by reburn technology.
Because the existing boiler was not designed with the anticipation of a future reburn system installation, the application of $NO_X$ emission control through reburn presents some additional problems: fuel combustion problems; boiler operating problems; reburn fuel availability and cost issues; physical constraints; particulate control device problems; and unit inflexibility. Boilers retrofitted with reburn will have less thermal efficiency and boilers may experience other operating problems with controlling steam temperature, increased fly ash production, boiler tube corrosion, and problems with boiler tube slagging.

Selective Non-Catalytic Reduction (SNCR)[5]

SNCR is a post-combustion process for $NO_x$ control that can reduce $NO_x$ emissions by 30 to 70%. The current SNCR technologies at TRP involves injection of urea into the flue gas. The overall reactions reduce $NO_x$ to nitrogen and water vapor and are similar to the selective catalytic reduction (SCR) reactions described below. In contrast with SCR, SNCR involves the reagent injection into high-temperature regions of the boiler to reduce $NO_x$ without the use of a catalyst. A catalyst is not necessary to support the reaction of reagent and NO at flue gas temperatures in the range of 1,400°F to 2,000°F. Above 2,000°F to 2,200°F, the reagent is oxidized to NO, and below 1,400°F the $NO_x$ reduction reaction stops. $NO_x$ reduction performance with urea is maximized in the narrow temperature window of 1,650°F to 2,100°F, but may vary with individual boilers[6].

At temperatures below the optimum SNCR operating temperature range, the ammonia ($NH_3$)/$NO_x$ reaction will not occur at the highest efficiencies, and un-reacted $NH_3$ will either be emitted as $NH_3$ slip, or it will react with $SO_3$ to form ammonium salts, or will be incorporated in the ash. Above the optimum temperature, the amount of $NH_3$ that oxidizes to $NO_x$ increases and the $NO_x$ reduction performance deteriorates rapidly. Both laboratory work and field data show $NH_3$ slip to be a strong function of temperature. At temperatures above 1,900°F, un-reacted $NH_3$ emissions decrease due to

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[2] Section 5.1.5. U.S. EPA, Office of Air Quality Planning and Standards, Alternative Control Technologies Document: NOx emissions from Utility Boilers (EPA-453/R-94-023), March 1994.
[3] U.S. Department of Energy, Office of Clean Coal Technology, Comprehensive Report to Congress: Clean Coal Technology Program – Demonstration of Coal Reburning for Cyclone boiler NOx Control, April 1990.
[4] Electric Power Research Institue, Cyclone NOx Control: Technology and Issues Assessment (TR-110499), December 1998.
[5] Montana Air Quality Permit #3175-04,
[6] EPA Air Pollution Control Cost Manual (6th Edition), January 2002

$NH_3$ oxidation to $NO_x$. At temperatures below 1,600°F, un-reacted $NH_3$ emissions increase. Laboratory data show that maximum $NO_x$ removal and lowest $NH_3$ slip can be achieved by injecting $NH_3$ in the narrow temperature window of 1,600°F to 1,900°F.

Flue gas temperatures in the stoker boiler furnace section, located between the grate and the flue gas passage into the convective section of the boiler, change when there are changes in boiler load, fuel characteristics, and combustion air temperature or flow. Because of this variability, the flue gas at the reagent injection point will not always be at the optimum temperature for $NO_x$ reduction.

The furnace section of the TRP coal/wood-fired, stoker boiler typically operates with temperatures in the range of 1,000°F to 2,000°F. As a result, during startup and shutdown, the boiler will not be able to achieve the higher end of potential $NO_X$ reductions (levels of up to 70% reduction) using SNCR technology. In addition, SNCR cannot be used when the boiler experiences low furnace temperatures.

Again, SNCR is already being used by TRP to control NOx emissions from the boiler along with simultaneous application of flue gas recirculation and overfire air (staged combustion, discussed above). However, these technologies are only partially effective at removing $NO_x$ during startup and shutdown events. According to TRP, Attachment 3, and the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department, the urea injection required for the SNCR should be initiated when the fire box (located 15 feet above the grate) temperature is approximately 1512 °F. In addition and based on information from Fuel Tech, Inc. (manufacturer of TRP's SNCR system), SNCR would not be effective at a heat input rate of less than 134 MMBtu/hr. Similarly, the function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of TRP's boiler combustion system manufacturer.

Selective Catalytic Reduction (SCR)

SCR is a flue gas treatment technique for controlling $NO_x$ that can reduce emissions by 50 to 90% on those sources where its application is technically feasible. SCR uses an $NH_3$ injection system and a catalytic reactor. Conventional SCR catalysts used to treat coal combustion flue gases operate in the temperature window of 500°F to 1000°F. An SCR system utilizes an injection grid, which disperses $NH_3$ in the flue gas upstream of the catalyst. $NH_3$ reacts with $NO_X$ in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$NH_3 + NO + 1/2\ O_2 \rightarrow N_2 + 3/2\ H_2O$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O$$

For the TRP stoker boiler, the SCR system would have to be located before the economizer where the temperature window is approximately 500°F. SCR also affects the overall plant operation, because $NH_3$ and $SO_3$ in the flue gas react to form ammonium sulfate and bisulfate upstream of the particulate control and flue gas handling equipment. Ammonium salt deposition could damage these controls and equipment. Because the SCR system is located upstream of the boiler economizer section where the flue gas temperatures are on the low end of the acceptable operating range, any changes in boiler operations, such as decreased load operation, will alter flue gas temperatures at the catalyst bed and can significantly affect SCR performance. Important operating and design factors associated with SCR include catalyst deactivation, problems with un-reacted $SO_3$ and $NH_3$, and process control limitations.

Catalyst deactivation and fouling results in is the loss of active catalyst necessary to promote the $NH_3/NO_x$ reaction. Catalyst deactivation primarily occurs via four mechanisms: poisoning, fouling, thermal degradation, and mechanical losses (i.e., erosion). Because the SCR system would be located upstream of the particulate control, mechanical losses and fouling have the potential to be significant problems with catalyst life due to the high dust/particulate load in the flue gas. Permanent catalyst poisoning results from alkaline metals and trace elements (e.g., Na, K, Ca, Mg and As) in coal. These elements will react irreversibly with the active acid sites on the SCR catalyst surface, thus poisoning the catalyst. Testing of a vanadium-titanium SCR catalyst, which is the predominant catalyst type, showed that alkali metals (i.e., Li, Na, K, Rb, and Cs) are strong catalyst poisons. The poisoning effect increases with metal basicity (i.e., K is a stronger poison than Na). Western coals and wood ash have high alkali metal contents. The alkali content of the ash from the TRC coal contains approximately 10% alkali, most of which would be potassium oxides. The high alkali metal content and the small size of stoker boilers are primary reason why SCR emission control technology has not been previously applied to stoker boilers.

**Step 2 – Technical Feasibility Analysis**

In this step, the technical feasibility of each remaining control option identified in the first step (above) is evaluated with respect to source-specific factors. According to the top-down BACT method described in the NSR Manual, if a control technology has been installed and operated successfully on a stoker boiler for startup and shutdown, it is demonstrated and it is technically feasible. Availability and Applicability are two key concepts that are used to determine is a proposed control technology is feasible.

TRP anticipates one startup period of 48 hours plus one shutdown period of 8 hours during each quarter for a total of 4 startups and 4 shutdowns per year. Because $NO_X$ is usually significant at high combustion temperatures of approximately 2,200ºF, with exponential increases in formation rate at higher temperatures, and startup and shutdown events occur over a much lower temperature range; many of the technologies evaluated will not provide additional control during startup and shutdown events.

The technologies to be reviewed with respect to technical feasibility (from Step 1) are as follows: FGR, combustion controls OFA with staged combustion and LEA, repowering, LNBs, reburn, SNCR, and SCR. OFA and staged combustion are already being used by TRP to control $NO_x$ emissions from the boiler along with simultaneous application of FGR. However, the function of the OFA and FGR is reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of TRP's boiler combustion system manufacturer. However, OFA with staged combustion, LEA, and FGR remain technically feasible because of their applicability to this boiler type.

For TRP, repowering would involve replacing the boiler in its entirety. Replacing the boiler would essentially redefine the source, and historically, the Environmental Protection Agency (EPA) has not considered redefinition of the source to be considered BACT. Therefore, TRP eliminated this technology because it is not technically feasible.

According to AP-42, section 1.1.4.3, LNBs can be applied to tangential and wall-fired boilers of various sizes but are not applicable to stoker boilers, and therefore LNB is not technically feasible.

The process of reburn could effectively reduce $NO_x$ emissions by 50-70%. It has been reported that at low load operations (similar to startup and shutdown events) where the reburn heat input is 30-35%, the predicted NOx emission reduction is approximately 46%[7]. Commercial experience seems to be limited to NOx emissions reductions for normal operations at full load, and primarily on boilers larger than TRPs. However, the reburn technology will continue to be analyzed as it may be technically feasible.

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[7] Curt Melland, Engineering Feasibility Study of Coal Reburn Application to the Cyclone Furnaces in North Dakota Lignite Cyclone Users Group, November 2001.

SCR would have limited potential to control NOx emissions during startup and shutdown events. SCRs are generally not demonstrated in the United States for wood fired boilers and the technology is considered technically infeasible for the TRP stoker boiler. In addition, the economic impacts were previously demonstrated to show that SCR technology is not economically viable for the TRP coal/wood-fired boiler even if the technical obstacles to SCR application could be overcome.

**Table I. Rank of Remaining Control Technologies.**

| Control Technology | Technically Available | Technically Feasible |
|---|---|---|
| SNCR | Yes | Yes |
| Reburn[8,9] | Yes | Yes |
| CC - OFA | Yes | Yes |
| CC - LEA | Yes | Yes |
| FGR | Yes | Yes |

**Step 3 – Rank Remaining Options by Control Effectiveness**

In Step 3, the control technology options determined to be technically feasible and available in Step 2 are ranked from the most to least effective according to emission reduction potential.

**Table II. Rank by Control Effectiveness.**

| Rank | Control Technology | Range of control for steady-state operation | Range of control efficiency for non steady-state |
|---|---|---|---|
| 1 | SNCR | 30-70[10]% | 0-50[11]% |
| 2 | Reburn[12,13] | 30-50 % | 0-46% |
| 3 | CC - OFA | 20-30% | 0-30% |
| 4 | CC - LEA | 10-20% | 0-20% |
| 5 | FGR | Minimal efficiency | Minimal efficiency |

**Step 4 – Evaluate Most Effective Controls and Document Results**

In step 4, the remaining control technologies are evaluated for energy, environmental and economic impacts of each option. This step generally validates and justifies the suitability of the top control option for selection of BACT. Beneficial and potential adverse impacts should be discussed and quantified. However, if the applicant has shown that the top alternative is shown to be appropriate, then the applicant does not need to evaluate the options any further.

[8] David Moyeda, GE Energy PowerPoint Presentation, May 2004
[9] US Department of Energy, Industrial Technologies Program, Award No. FC36-99GO10418, 2006
[10] Sierra Research, e-mail from Gary Rubenstein, November , 2008
[11] Sierra Research, e-mail from Gary Rubenstein, November , 2008
[12] David Moyeda, GE Energy PowerPoint Presentation, May 2004
[13] US Department of Energy, Industrial Technologies Program, Award No. FC36-99GO10418, 2006

Because of the variability of operating scenarios and the unknowns during startup and shutdown, specific emission performance levels were not considered in this analysis. A complete analysis of the potential energy, environmental, and economic impact of the TRP-specific application of SNCR, FGR and combustion controls (existing control) to the proposed project is detailed in the application for Permit #3175-04 and supporting materials (i.e., referenced permit application #3175-03).

The cost effectiveness of TRP retrofitting the existing boiler reburn technology was determined to be approximately $1,284,855/ton of NOx reduction. Given the distance to an existing natural gas line (> 80 miles) and the fact that boilers retrofitted with reburn technology usually have less thermal efficiency and may experience other operating problems with controlling steam temperature, increased fly ash production, boiler tube corrosion, and problems with boiler tube slagging; the Department has determined that retrofitting the boiler with reburn technology does not constitute BACT.

In addition, OFA is currently operated at TRP and achieves a higher $NO_x$ reduction than LEA. Therefore, LEA was eliminated from further analysis.

Startup
74 lb/hr * 48 hrs/event * 4 events/yr * 0.0005 ton/lb = 7.10 ton/yr

Shutdown
74 lb/hr * 8 hr/event * 4 events/yr * 0.0005 ton/lb = 1.18 ton/yr

Total Annual NOx Emissions for Startup/shutdown
7.10 ton/yr + 1.18 ton/yr = 8.28 ton/year

**Step 5 – Select BACT**

Under the current permit action, TRP proposed and the Department concurred that best management practices (including CC), SNCR in combination with the existing OFA and FGR combustion controls constitutes BACT for the control of $NO_x$ emissions from the boiler during startup and shutdown events.

Because the effectiveness of control equipment is highly dependent on specific boiler operating characteristics and control equipment operating parameters, NOx emissions from the boiler stack will vary during startup and shutdown events. TRP must proceed with startup and shutdown of the boiler in a manner that minimizes emissions, in accordance with written procedures that meet certain specific requirements set forth in this permit and outlined in Attachment 3, as further described in the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

Second, the Department determined that inclusion of a boiler $NO_x$ emission limit of 74.0 lb $NO_x$/hr would be applicable during defined periods of startup and shutdown. Based on information from Fuel Tech, Inc. (manufacturer of SNCR system), the SNCR unit would not be effective at a heat input rate of less than 134 MMBtu/hr. The function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of the boilers combustion system manufacturer. Therefore, a short term limit considering no control and maintaining compliance with the applicable ambient air quality standards is necessary in order for the TRP boiler to operate within the requirements of the permit. Assuming an uncontrolled $NO_x$ emissions rate of 0.55 lb/MMBtu (AP-42, Section 1.1) and a boiler heat input rate of 134 MMBtu/hr (effective $NO_x$ control cut-off level), uncontrolled $NO_x$ emissions from the TRP stoker boiler firing subbituminous coal would be 74.0 lb/hr. It should be noted that through the permit application process for MAQP #3175-04, TRC demonstrated compliance with the applicable ambient air quality standards by modeling an emissions rate of 195 lb $NO_x$/hr. Therefore, a $NO_x$ emission rate of 74 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards.

Finally, boiler startup operations, as described in the *Best Management Operational Practices for Startup and Shutdown Events* and generally described in Attachment 3 of MAQP #3175-06, shall not exceed 48 hours from initial fuel feed to the boiler pre-heater or boiler, whichever is applicable at initiation of the boiler startup event. Boiler shutdown operations, as outlined in the *Best Management Operational Practices for Startup and Shutdown Events* and generally described in Attachment 3, shall not exceed 8 hours from initial backing down of solid fuel feed (coal and/or wood-waste) to the boiler.

In summary, after evaluation of the previously discussed information, the Department determined that the operation of OFA and FGR combustion controls and SNCR to achieve 74.0 lb/hour based on an hourly average constitutes BACT, in this case.

**$SO_2$ BACT Analysis for Startup and Shutdown Events**

**Step 1 - Identify All Control Technologies**

$SO_2$ and sulfur trioxide ($SO_3$) are two sulfur oxides ($SO_x$) that are formed whenever any material containing sulfur is burned. Emissions from fossil fuel combustion consist primarily of $SO_2$. Additional compounds of $SO_x$ also form at a much lower quantity and consist of sulfur trioxide ($SO_3$) and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process.

Prior to evaluating control options for $SO_2$ during startup and shutdown events, it is important to clarify what constitutes startup and shutdown. A startup event takes the facility from a non-operational condition to a steady-state electrical load condition. During the startup process, TRP goes through a number of steps for a cold start or a warm re-start until the system is brought up to a steady-state load. A shutdown event takes the boiler from a steady-state electrical load condition to a non-operational condition, or from a mid startup condition to a non-operating condition. TRP anticipates one startup period of 48 hours plus one shutdown period of 8 hours during each quarter for a total of 4 startups and 4 shutdowns per year. The process of startup and shutdown is further discussed in Attachment 3 and the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

The US EPA RBLC, CARB's BACT database, BAAQMD BACT Guidelines, and SCAQMD BACT Determinations were reviewed to identify the possible types of $SO_2$ controls permitted for coal/wood-fired boilers during startup and shutdown events[14].

Review of these databases for BACT during non-steady state operation identified only startup and shutdown conditions for a circulating fluidized bed combustion boiler in Illinois that utilized lime injection which is similar to the lime spray dryer (LSD) flue gas desulfurization (FGD) systems currently applied at TRP. The RBLC identified varied flue gas desulfurization (FGD) unit for steady-state operations and for the control of $SO_2$. These FGD technologies are discussed in greater detail below, however, all have limited capabilities during startup and shutdown events.

Based on review of available literature, and without regard to feasibility, TRP evaluated the following control options for $SO_2$ emissions from the boiler during startup and shutdown events:

- Coal sulfur properties;
- Coal cleaning;
- Flue gas desulfurization (FGD);
- Wet scrubbers;
- Spray dry absorption;
- Best Management Practices (lime injection)

[14] Sierra Research, BACT Analysis for TRP, May 30, 2008

Coal Sulfur Properties

With any wood/coal fired steam co-generation plant, the properties of fuel varies and the choice of fuels utilized directly impacts the amount of $SO_2$ emissions. In general, low-sulfur coal reduces the sulfur fed to the boiler and is generally a highly effective way to reduce $SO_2$ because approximately 95% of the fuel sulfur is converted to $SO_2$ during combustion; the remainder is typically bound in the ash.

Coal Cleaning[15]

Coal is a heterogeneous mixture of organic and inorganic matter. The inorganic impurities in coal include: rocks, overburden (soil), and pyrite (iron disulfide, $FeS_2$). Coal cleaning can be used to separate organics and inorganics. Various coal cleaning processes (physical, chemical or biological) may be employed to improve coal quality and reduce coal sulfur content:

Physical: Inorganics can be physically separated to varying degrees through physical coal cleaning. Sulfur is generally present in coal in three forms: pyritic, sulfate, or organic. The pyritic portion of sulfur in coal may vary from 30% to 70% of the total sulfur content and large pyrite particles can be removed by physical cleaning. Physical coal cleaning techniques take advantage of the differences in specific gravity of the coal and its impurities. However, sub-bituminous coals used at TRP have inherently low sulfur content; therefore, physical cleaning of pyrite crystals from the coal is not expected to significantly reduce emissions during startup and shutdown events.

Chemical Cleaning: Sulfur chemically combined with the carbon in coal, or organic sulfur, cannot be removed by physical cleaning, nor can nitrogen be removed. Chemical cleaning is used to remove organic sulfur from the coal. One technique is called molten-caustic leaching in which coal is submerged in a chemical that actually leaches the sulfur and other minerals from the coal.

Biological cleaning: Biological cleaning involves using bacteria that literally "eat" the sulfur out of the coal. Scientists are trying to improve the sulfur-removing characteristics of the bacteria through experimentation. Other scientists are using fungi, while still others are trying to find a way to duplicate the enzyme, or chemical, inside of the bacteria that eat the sulfur. They can then inject the enzyme directly into the coal to speed the cleaning process.

Flue Gas Desulfurization[16]

Flue gas desulfurization (FGD) systems are primarily designed to reduce emissions from combustion exhaust and there are several ways to classify FGD systems: 1) throwaway or regenerative, and 2) wet or dry. For the throwaway process, the sulfur removed from the flue gas is discarded. Regenerative is when the sulfur is recovered and re-used in another form. Wet or dry refers to the phase in which the main reaction occurs and either of these could result in throwaway or marketable by-product[17].

*Wet FGD* process processes mix aqueous alkaline solutions or slurries consisting of lime or limestone as the $SO_2$ absorbent medium to remove $SO_2$ and acid gases from the combustion exhaust. Insoluble salts form in the chemical reactions that occur as the reagent comes in contact with the exhaust gas. The salts are then removed as a solid waste by-product that is treated and dewatered. Depending on the type of treatment applied, the solid waste is either disposed of or sold for beneficial use.

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[15] Illinois Department of Commerce and Community Affairs, Office of Coal Development and Marketing
[16] Department of Environmental Quality, MAQP #3175-04, September 2006
[17] C. David Cooper and F.C. Alley, Air Pollution Control-A Design Approach, 1986.

*Dry FGD* uses the same principles as Wet FGD to reduce $SO_2$ and acid gas emissions except there is no liquid waste stream. Dry FGD inject a dry alkaline powder, hydrated limestone, or high-solids slurry into the exhaust stream and the reagent mixes and reacts with $SO_2$ and acid gases to form a solid particulate that are collected and removed by particulate emissions control equipment and removed.

Although regenerable systems minimize waste generation, these systems have very high capital and operating costs and are not used to any significant extent in the U.S. These systems are used where very large amounts of $SO_2$ are being removed and where waste disposal is not economically feasible. Likewise, non-regenerable FGD systems are typically divided into systems having low capital costs and high capital costs. The high capital cost systems are economical where very high $SO_2$ removal rates are desired and large amounts of $SO_2$ must be removed. Low capital cost systems are economical where moderate to high $SO_2$ removal rates are desired and small amounts of $SO_2$ must be removed. Low capital cost systems are also more economical for retrofit applications because of the increased capital costs associated with retrofitting large amounts of equipment at compact plant sites.

*Wet limestone scrubber systems* (WSS) and *lime spray dryer* (LSD) absorbers are FGD technologies used in $SO_2$ removal. Typically in the United States these FGD systems are favored because of their simplicity of operation and equivalent removal capabilities compared to relatively complex byproduct recovery FGD systems. WSS and LSD FGD systems have the advantage of using low-cost widely available calcium-based additives. WSS sodium-based systems are economical where the liquid waste can be economically treated before discharge to a water source and the amount of $SO_2$ to be removed is small (cost of soda ash/sodium hydroxide is prohibitive relative to lime or limestone for moderate to high amounts of $SO_2$ removed). Because the TRC application constitutes a relatively small amount of $SO_2$ to remove and sodium sulfate salts can be disposed of WSS has been evaluated further. WSS can achieve 95% removal.

*WSS FGD* comprises relatively large capital equipment and operating costs compared to the LSD FGD system. Therefore, WSS FGD are typically used for large coal-fired power plant applications where tens of thousands of tons per year of $SO_2$ are being removed. As previously indicated the WSS FGD application can achieve 90 to 95% removal. However, considering WSS FGD for a 192.8 MMBtu/hr application using low sulfur coals would incur extremely high capital and operating costs for the removal of a small amount of $SO_2$ relative to large, utility coal-fired boilers.

*LSD FGD* has moderate capital equipment and operating costs compared to a WSS FGD system. Because the TRC boiler already has a BACT determined fabric filter baghouse for $PM/PM_{10}$ control, the cost of the LSD FGD system is further reduced. A LSD FGD system with a fabric filter can achieve 85 to 90% removal. Therefore, on an economic basis, the retrofit of a LSD FGD system is evaluated further in the BACT analysis.

Because of the higher capital costs and space requirements for LSD FGD technologies, dry sorbent injection (DSI) technology using hydrated lime and/or sodium carbonates is expected to be more cost-effective where small amounts of $SO_2$ need to be removed. Therefore, the use of a hydrated lime/sodium bicarbonate DSI on the stoker boiler to control annual average $SO_2$ emissions by 50 to 90% is also evaluated.

*Lime Spray Dryer Absorber System (LSD)* is a two-stage process that removes $SO_2$ from the flue gas through the use of a spray dryer/absorber followed by a fabric filter baghouse. The absorber module serves as the initial contact zone where alkaline additive (calcium hydroxide) and $SO_2$ in the flue gas react to form dry reaction products. The majority of reaction products formed in the spray dryer flow out of the absorber module and into the fabric filter for removal with the fly ash.

The absorber module is sized on the basis of gas flow rate and residence time. Residence times of approximately 10 seconds have proved sufficient to ensure adequate reaction product drying. The atomizers, which disperse the additive slurry, are sized on the basis of additive and tempering water feed necessary to achieve the required $SO_2$ removal level and outlet gas temperature.

Flue gas temperatures at the fabric filter inlet must be sufficiently high to avoid corrosion in the fabric filter and in other downstream equipment. Low flue gas temperatures can also cause condensation of cementitious fly ash materials on the filter bags, severely degrading bag life and fabric filter operation. Adjustment of the spray dryer module approach temperature (number of degrees that the spray dryer operates above the saturation temperature) determines the spray dryer module outlet gas temperature. The amount of water added to the slurry is adjusted to control the spray dryer module outlet gas temperature. For the same $SO_2$ removal efficiency, a higher approach temperature results in greater lime consumption. Lime consumption increases as a result of a reduction in the $SO_2$ removal reaction efficiency at the higher approach temperature. An "approach temperature" (i.e., approach to saturation temperature) of 38°F results in a fabric filter inlet gas temperature of approximately 165°F. An inlet gas temperature of 165°F is sufficiently high to protect the fabric filter and other downstream equipment.

The preparation of lime for use as an additive in a spray dryer is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is pumped to the additive feed tank. Since a significant portion of the lime feed does not initially react with the $SO_2$ in the flue gas stream, a portion of the solids collected in the fabric filter is returned and mixed with fresh lime slurry so that unreacted lime or alkalinity contained in the fly ash can be utilized. The lime and recycled solids are blended in a recycle slurry mix tank and pumped to the additive feed tanks. The solids collected in the fabric filter, which are not recycled to the additive preparation system, are collected in the solids storage silo and subsequently transported by trucks to a landfill. This process uses about a third less water than do the WSS FGD processes. For purposes of this BACT, an 85-90% $SO_2$ removal efficiency is assumed.

For LSD FGD, guaranteed 85% $SO_2$ removal can be obtained from control equipment manufacturers and there are several reference facilities in operation at 80% plus efficiency when combusting low sulfur coal, at conditions very close to TRC's conditions. The technology is not new, and this is not a "pioneering" application for 80-85% removal on 0.5% sulfur coal at reasonable calcium to sulfur stoichiometries. Recycle of baghouse fly ash, unused lime and reaction products is not necessary at 80-85% removal efficiencies, eliminating the accelerated erosion of ducts and bags which accompany high baghouse ash recycle rates, and which increase maintenance and operating costs, plus the chance of unplanned outages. 90% removal can be achieved at much higher stoichiometries, but the only guarantees which can be given at 90% require recycle of baghouse ash and high recycle rates, resulting in accelerated erosion of ducts and bags, increased atomizer maintenance and operating costs, and increased chance of unplanned outages. A number of suppliers have experience with multiple installations of the absorption equipment and the auxiliary equipment, which has to be included. For reference only, to go from 85% removal at about 200% stoichiometry (conservative, but achievable even without perfect tuning) to 90% removal will require an increase in stoichiometry to 220% meaning 120% unused lime instead of 100% unused lime to the landfill (about 1,400 pounds per day) plus the additional reaction products. This means more than 550,000 pounds per year more landfill (and materials handling) to get a routine 90% instead of 85% removal (93,160 pounds per year more $SO_2$ removed). LSD FGD is expensive for achieving 90% sulfur control on low sulfur Western coals as currently burned by TRC.

*Dry Sorbent Injection Scrubbing System (DSI)*. The DSI system is a two-stage process that removes both $SO_2$ and particulate from the flue gas through the use of flue gas ductwork residence time followed by a fabric filter. The alkali sorbent is injected into the existing ductwork, the initial contact zone, where alkaline additive (lime, sodium carbonates, etc.) and $SO_2$ in the flue gas react to form dry reaction products. The reaction products formed in the ductwork flow into the fabric filter for removal with the fly ash.

A sodium alkali DSI system has the advantage over calcium-based alkali DSI systems for two reasons. First, the amount of sorbent necessary for injection is less because sodium sorbents are more reactive than calcium-based sorbents. And, secondly, the utilization of the sorbent is higher because of the higher reactivity. This double effect significantly reduces the increased particulate loading to the fabric filter and significantly reduces the amount of wasted/unreacted sorbent. The disadvantage of the sodium alkali injection system is the much higher cost of the sodium alkali relative to a calcium-based alkali. Additionally, sodium sulfate salts are much more water-soluble than calcium sulfate salts. This process uses very little water.
A DSI system can achieve up to 90% removal. However, a DSI system operates more efficiently at high sulfur inlet loading. Using low sulfur coals does not allow the DSI system to reach maximum design removal efficiency. For purposes of this BACT, an 80% $SO_2$ removal efficiency is assumed.

According to MAQP #3175-04, TRC received vendor quotations and information from two DSI suppliers, which claimed that 80 to 90% $SO_2$ control was achievable on a 30-day rolling average. However, upon detailed review of the vendor supplied information and guarantees, TRC concluded that neither proposal is attractive for many reasons. Despite some significant differences, the proposals use almost identical $SO_2$/hydrated lime absorption methods. They rely on the "new" lime being wetted (thus semi-dry) and then mixing the wetted new sorbent with huge quantities of dried, recycled lime, reaction products and flyash. This would create an enormous surface area available for absorption. Both vendors claim $SO_2$ removal results, which are better than what other prevailing suppliers guarantee with semi-dry methods on Western low sulfur coal. They are both what can be described as alternative technologies to the norm, not well proven, and neither has been demonstrated, even on small scale, on low sulfur Western coal, which is a serious potential problem for TRC.

One vendor's guarantee is based on TRC heating the flue gas up to a minimum of 300°F requiring 2 MMBtu/hr of natural gas or an energy loss of 2 MMBtu/hr from flue gas heat recovery. Both the operating and capital costs are much higher than expected for this system. The lime stoichiometry is not guaranteed and thus, the remedy for non-performance will be more lime. The other vendor did not provide any guarantees.

Best Management Practices

The key to minimizing emissions during startup and shutdown events considers management of air and fuel properties, and the initiation of reagent injection at the earliest possible point in the startup process. TRP proposes to operate the boiler in a manner that minimizes emissions during startup and shutdown, and in accordance with written procedures that meet certain specific requirements set forth in this permit and outlined in Attachment 3, as further described in the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

**Step 2 – Technical Feasibility Analysis**

Again, TRP anticipates one startup period of 48 hours plus one shutdown period of 8 hours during each quarter for a total of 4 startups and 4 shutdowns per year.

With respect to coal cleaning, commercially cleaned coal is not available in the area. There was a syncoal facility that once operated near Colstrip, however it has since been shut down. A process to develop commercially cleaned coal in Wyoming (called Cowboy Coal) is in the development stages, but has not reached commercial operation. And although there are many options for coal cleaning technology TRP has determined that they are not feasible or commercially available in this region. Given the fact that TRP will have minimal $SO_2$ emissions during startup and shutdown events and the intrinsically low sulfur content of the coal used at TRP, and that RBLC database does not recognize coal cleaning, it was eliminated from further analysis.

The following table summarizes the characteristics of the different types of FGD systems and the rationale for consideration in this BACT analysis with respect to technical feasibility.

**Table IV. FGD System Characteristics.**

| FGD System | % Reduction | Advantage | Disadvantage | Rationale |
|---|---|---|---|---|
| Regenerable or Byproduct Recovery (Dual Alkali, Magnesium Oxide, Wellman-Lord) | 95+ | Minimizes waste disposal High $SO_2$ removal capability | Very high capital and operating costs. Not economical unless large amount of $SO_2$ to be removed and waste disposal costs are high. System has large footprint. | Excluded from analysis because the small amount of $SO_2$ to be removed during startup and shutdown makes technology economically infeasible. |
| Non-regenerable – High Capital Cost (lime/lime-stone wet and dry FGD and wet sodium FGD) | 70-95 | Lower capital and operating costs than regenerable systems when waste disposal costs are moderate to low | High capital and operating costs. Generates large volumes of waste. Not economical unless moderate to large amount of $SO_2$ to be removed. System has large footprint. | Wet lime/ limestone FGD not analyzed because of the small amount of $SO_2$ to be removed. Lime spray drying analyzed because typically used for small systems (e.g., municipal waste combustors). Wet sodium FGD analyzed because onsite treatment of liquid, sodium-containing waste assumed to be available. |
| Non-regenerable – Low Capital Cost (dry and wet sorbent injection using calcium and sodium compounds) | 40-90 | Low capital and operating costs. System has small footprint. | High chemical consumption and high operating costs where moderate to large amounts of $SO_2$ to be removed. Generates large volumes of waste. | Dry and wet lime injection selected due to small amount of $SO_2$ to be removed and limited footprint at plant. |

These control technologies were evaluated for steady-state operations and found to be technically available and feasible.

**Table V. Rank of Remaining Control Technologies.**

| Control Technology | Technically Available | Technically Feasible |
|---|---|---|
| Minimization of coal sulfur content | Yes | Yes |
| DSI | Yes | Yes |
| WSS | Yes | Yes |
| LSD | Yes | Yes |
| BMP | Yes | Yes |

All of these technologies with the exception of minimization of coal sulfur content and best management practices will have limited potential to control $SO_2$ during startup and shutdown events. TRP has evaluated these control technologies and most have not been demonstrated in the United States (US) for startup and shutdown.

**Step 3 – Rank Remaining Options by Control Effectiveness**

**Table VI. Rank by Control Effectiveness.**

| Rank | Control Technology | Range of control for steady-state operation | Range of control efficiency for non steady-state |
|---|---|---|---|
| 1 | WSS | 90-95% | 0-95% |
| 2 | LSD | 85-92[18]% | 0-92% |
| 3 | DSI | 80-90% | 0-90% |
| 4 | Minimization of coal sulfur content | Permit limit | Permit limit |
| 5 | BMP | Varies | varies |

Startup
155 lb/hr * 48 hr/event * 4 events/yr * 0.0005 ton/lb = 14.88 ton/yr

Shutdown
155 lb/hr * 8 hr/event * 4 events/yr * 0.0005 ton/lb = 2.48 ton/yr

Total Annual $SO_2$ for Startup/shutdowns
14.88 ton/yr + 2.48 ton/yr = 17.36 ton/year

**Step 4 – Evaluate Most effective Controls and Document Results**

Because DSI ranked low in comparison to LSD and WSS, it was removed from consideration. Although WSS is ranked higher, TRP installed the $SO_2$ control technology of spray absorption (LSD) under MAQP #3175-04. In addition to economic reasons for eliminating WSS, WSS uses

[18] Sierra Research, Application information for MAQP#3175-06, August, 2008

more energy and water, and requires wet sludge handling equipment. Because the technologies have roughly comparable efficiencies for $SO_2$ but LSD is available on-site and is technically feasible, the Department has removed WSS from further consideration.

A complete analysis of the potential energy, environmental, and economic impact of the TRP-specific application of LSD (existing control) to the proposed project is detailed in the application for Permit #3175-04 and supporting materials (referenced permit application #3175-03). Additionally, MAQP # 3175-04 and the associated $SO_2$ BACT analysis selected a LSD FGD unit with a guaranteed control efficiency of 85% $SO_2$ removal as BACT. All of the above technologies have been previously been evaluated by the Department for steady-state emissions and were eliminated from consideration. Because this permit action involves a minor amount of emissions where control equipment will be limited by the boiler's operation during startup and shutdown, the other control technologies were not evaluated further.

**Step 5 – Select $SO_2$ BACT for Startup and Shutdown Events**

Under the current permit action, TRP proposed and the Department concurred that best management practices, limit on sulfur content of coal during these events ($\leq$0.745 lb S/MMBtu), in addition to LSD FGD constitutes BACT for the control of $SO_2$ emissions from the boiler during startup and shutdown events.

Because the effectiveness of control equipment is highly dependent on specific boiler operating characteristics and control equipment operating parameters, $SO_2$ emissions from the boiler stack will vary during startup and shutdown events. TRP must proceed with startup and shutdown of the boiler in a manner that minimizes emissions, in accordance with written procedures that meet certain specific requirements set forth in this permit and outlined in Attachment 3, as further described in the *Best Management Operational Practices for Startup and Shutdown Events* on file with the Department.

Second, the Department determined that inclusion of a boiler $SO_2$ emission limit of 155.0 lb $SO_2$/hr would be applicable during defined periods of startup and shutdown and this was shown through previous modeling (applications for MAQP #3175-04 and #3175-03) to be protective of the applicable ambient air quality standard(s). Based on information from Hamon Research Cottrel and again confirmed by TRP, the FGD $SO_2$ control equipment would not be effective at a heat input rate of less than 103.7 MMBtu/hr. Therefore, a short term limit is appropriate considering the range of partial control to no control during these events, and the fact that this limit maintains compliance with the applicable ambient air quality standards.

TRP estimates the average sulfur content of coal burned at approximately 0.7% by weight. The typical heat content of coal burned at TRP varies from approximately 10,000 to 10,500 Btu per pound on an as-received basis. TRP estimates that the typical coal received is approximately 10,200 Btu per pound. The table below provides a summary of coal parameters that were used in this BACT analysis.

**Table III. Coal Specifications.**

| COAL PARAMETER | PERMIT LIMITS | TYPICAL COAL |
|---|---|---|
| Heat content (Btu/lb) | ≥ 8,000 | 10,200 |
| Sulfur content (lbs S/MMBtu) | ≤ 0.745 | ≤ 0.745 |

TRP proposes to use low sulfur coal and proposes to balance the heat content and/or the sulfur content (by weight) in order to maintain the sulfur content at less than 0.745 lb S/MMBtu at all times. For instance, if the heat content of coal is 10,200 Btu/lb then the sulfur content (by % weight) shall not exceed 0.76. However, if the heat content of coal is 8,000 Btu/lb the sulfur content (by % weight) shall not exceed 0.6. Both scenarios result in a sulfur heat content of 0.745 lb S/MMBtu.

The Department concurs that limiting coal to no more than 0.745 lb S/MMBtu and no less than 8,000 Btu per pound heat content would be appropriate to ensure the startup and shutdown limits on $SO_2$ would be complied with. TRP presented all operating scenarios that could occur on-site to show that 0.745 lb S/MMBtu would be protective of the NAAQS and would be less than the $SO_2$ emission limit of 155.0 lb $SO_2$/hr. Assuming an uncontrolled a boiler heat input rate of 103.7 MMBtu/hr (effective $SO_2$ control cut-off level), and a fuel sulfur level of 0.745 lbs S/MMBtu (equivalent to sulfur content of 0.76 % (by weight) results in an uncontrolled $SO_2$ emissions from the TRP stoker boiler firing subbituminous coal would be 154.5 lb/hr.

Again, through the permit application process for MAQP #3175-04, TRP demonstrated compliance with the applicable ambient air quality standards by modeling an emissions rate of 155 lb $SO_2$/hr. Therefore, a fuel sulfur level limit of less than or equal to 0.745 lb S/MMBtu, best management practices and an emission rate of 155 lb $SO_2$/hr constitutes BACT and has been shown to be protective of the health-based ambient air quality standards.

**NOx BACT Analysis for Ash-Pulling Periods**

**Step 1 - Identify All Control Technologies**

The first step in a top-down BACT analysis is to identify all "available" control options for the pollutant and emission unit in question. The Board's decision to remand MAQP #3175-04 specifically stated that the Department must conduct a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. The non-steady state BACT determination must also include an analysis of the impact of the new BACT standards on overall BACT determined emission limits for $NO_x$ and $SO_2$ and whether the overall BACT limits and averaging time should be adjusted through a new BACT analysis.

As an introduction to the detailed discussion of $NO_X$ control technologies, it is useful first to review what is considered an ash-pulling event/period for the boiler. The TRP boiler has two bottom ash hoppers associated with clinker grinder that are located in the basement of the boiler building that collect ash. Each clinker grinder is manually operated from control panels located next to each grinder. During normal boiler operations (operating at full capacity), the operator empties the bottom ash hoppers every 12 hours by opening the hopper sliding door to allow draining of the accumulated ash into the clinker grinder. The grinder reduces the ash size so it can readily pass through and occasionally the process requires manual raking or lancing the larger debris. TRP has estimated that ash-pulling events will take approximately 1-hour to complete and would occur two times per day. Ash-Pulling periods cause disruption in operating temperatures and the overall combustion process by flooding the lower furnace with air and increasing thermal NOx emissions. The ash-pulling periods will result in $NO_X$ emissions of approximately 20 tons per year. The process of ash-pulling is further discussed in Attachment 4 and further detailed in the *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department.

The US EPA RBLC, CARB's BACT database, BAAQMD BACT Guidelines, and SCAQMD BACT Determinations were reviewed to identify the possible types of $NO_x$ controls permitted for coal/wood-fired boilers during ash-pulling periods.

Review of these databases for BACT during ash-pulling periods did not identify any available control options. However, based on review of available literature, and without regard to feasibility, TRP evaluated the following control options for $NO_x$ emissions from the boiler during ash-pulling periods:

- Best Management Practices;
- Combustion Controls;
    - Modification to Boiler;
    - Frequency and Duration of Events;

- Automatic Ash-pulling;
- Repowering;
- Low $NO_x$ Burners;
- Coal Specification;
- Staged Combustion
- Reburn;
- Selective non-catalytic reduction; and
- Selective Catalytic reduction

SNCR is already being used by TRP to control NOx emissions from the boiler along with simultaneous application of flue gas recirculation and overfire air (staged combustion, discussed above). TRP evaluated all of the same NOx control technologies that were evaluated for startup and shutdown events. Descriptions of these technologies can be viewed in the above "NOx BACT for Startup and Shutdown Events" section.

In addition to the control technologies, work practices, and best management practices that have already been selected as BACT under this permit action and MAQP #3175-04, TRP evaluated the following additional methods to control NOx:

<u>Best Management Practices (BMP)</u>

TRP proposes to implement *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department (and outlined in Attachment 4) to minimize $NO_X$ emissions. One of the key items to BMP is to preclude the operator from opening the clinker grinder inspection door and the bottom ash hopper sliding gate at the same time. In addition, TRP has outlined the ash-pulling process which allows the operation a systematic approach to ash-pulling. Additionally, this approach to ash-pulling periods will assist with management of air and fuel flow.

<u>Combustion Control (CC)</u>

Thermal $NO_X$ can be reduced by minimizing the amount of excess oxygen, delaying the mixing of fuel and air through good combustion design. Fuel $NO_X$ can be reduced by suppressing the amount of air required for complete combustion in the primary combustion zone (on the grate for stoker boilers), and by using low nitrogen fuels. However, coal is not generally characterized by its nitrogen content and the stoker boiler already inherently operates with lower oxygen levels at the grate and higher oxygen levels in the furnace. For TRP's stoker boiler, ash-pulling periods introduce additional oxygen which throws off the combustion process and the generation of thermal NOx and fuel NOx.

Because ash-pulling periods are required for proper operation of the TRP boiler, TRP evaluated several options to assist with combustion control, such as: modification to the boiler, duration and frequency of these events, and a guidance document outlining a systematic approach to ash-pulling events for operators (see Attachment 4).

*Boiler Modification*: The boiler modification adds small ports (equipped with caps) for inspection and to allow the manual use of a rod to break up large bottom ash clinkers and move clinker to the discharge position for the grinder. This approach limits the amount of excess air introduced to the boiler and precludes the operator from opening the doors to rod the clinker and limits disruption to the boiler.

*Duration and Frequency:* Modification to the boiler in addition to the best management practices should decrease the duration of the ash-pulling events. TRP has proposed 1-hour ash pulling events twice per day rather than 2-hours, twice per day.

Automatic Ash-Pulling

TRP evaluated the current ash-pulling process to determine if automatic ash-pulling would result in lower $NO_X$ emissions. According to TRP, automatic ash-pulling would require that bottom of the stoker boiler to be modified by adding a computer controlled process that automatically opens the bottom ash hopper sliding grate to dump clinker ash into the grinder.

**Step 2 – Technical Feasibility Analysis**

Because the Department has already analyzed all of the technologies listed in Step 1 in prior sections of this BACT analysis and determined which control options constitute BACT for $NO_X$ and $SO_2$ during non-steady state operations, no further analysis is required for these control options. In addition, TRP believes that ash-pulling events will be considered steady-state operation. Therefore, the Department did not re-evaluate: repowering; Low NOx Burners; Coal Specification; Staged Combustion; Reburn; NSCR; or SCR. These options have already been evaluated under MAQP #3175-04 for steady-state operations and further analysis is not necessary.

With respect to automatic ash-pulling, TRP has determined that while this process is feasible, it would not result in a decrease in $NO_X$ emissions. Both automatic and manual ash-pulling processes associated with stoker boilers results in non-design air flowing into the boiler and disrupting the combustion process. In addition, TRP's boiler operation relies heavily on visual observation to identify the presence of a problem with the ash clinker and the potential to clog or block the grinder. Therefore, automatic ash-pulling would not provide any additional benefit and has been eliminated from further consideration.

TRP anticipates two ash-pulling periods per day and the duration of these events is estimated at approximately 30-60 minutes. The remaining control technologies were evaluated for steady-state operations.

**Table VII. Rank of Remaining Control Technologies.**

| Control Technology | Technically Available | Technically Feasible |
|---|---|---|
| BMP | Yes | Yes |
| CC | Yes | Yes |

**Step 3 – Rank Remaining Options by Control Effectiveness**

**Table VIII. Rank by Control Effectiveness.**

| Rank | Control Technology |
|---|---|
| 1 | CC |
| 2 | BMP |

**Step 4 – Evaluate Most effective Controls and Document Results**

TRP plans to implement all of the items discussed for CC and BMPs. Because all other options were eliminated or were already required as BACT for steady-state operations, and TRP has adopted the remaining control options for ash-pulling periods, no further analysis is necessary. The Department has determined CC and BMP for Ash-pulling events constitutes BACT.

**Step 5 – Select BACT**

Under the current permit action, TRP proposed and the Department concurred that BMP, CC, and proper operation of SNCR in combination with the existing OFA and FGR combustion controls constitutes BACT for the control of $NO_x$ emissions from the boiler during ash-pulling events.

Because the effectiveness of control equipment is highly dependent on specific boiler operating characteristics, control equipment operating parameters, and the proposed modifications to the boiler NOx emissions from the boiler stack will vary during ash-pulling events. With the modifications to the boiler and operating procedures, TRP believes they can meet steady-state emission limits for $NO_X$ during ash-pulling periods but does not have an emission data to base this on.

Therefore, TRP proposed a 60-day "monitoring period" following commencement of commercial operation to collect data during ash-pulling periods according to the *Monitoring Plan to Determine Emission Limits During Ash-pulling Periods* on file with the Department in order to verify NOx emissions. Under this permit action, the Department required that TRP collect 30-days of certified NOx CEMs data. TRP has the ability to collect up to 180 days of certified NOx data for ash-pulling periods, but the data collection must be completed within 180 day of commencement of commercial operations or initial boiler startup. In an effort to limit the amount of additional time for monitoring during ash-pulling periods, the Department concluded that the data must be collected by a certified monitor and must be acquired within 180 days of initial startup of the boiler or commencement of commercial operations following issuance of MAQP #3175-06.

The data gathered during the monitoring period shall be reported as outlined in Attachment 5 and must be submitted to the Department at least 15-days following completion of the monitoring period, but no later than 195 days following commencement of commercial operation or initial startup of the boiler following issuance of MAQP #3175-06. TRP's report to the Department shall include: 1) verification that TRP can meet steady-state NOx limits outlined in Section II.D.14.a.i. and 14.a.iii; or 2) a permit modification to establish permit limits during ash-pulling periods.

In any event, TRP must proceed with ash-pulling in a manner that minimizes NOx emissions by implementing BMP and CC, by modifying the boiler to add inspection ports for "rodding", and by following good combustion control in accordance with *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department (and outlined in Attachment 4). The Department has determined that CCs and BMPs constitutes BACT until such time that NOx limits can either be verified or established under a permit modification.

In the event that TRP is unable to meet steady-state limits and is required to submit a permit modification for ash-pulling periods, TRP will be subject to a temporary BACT limit established for non-steady state operations (startup and shutdown limits). This temporary BACT limit is subject to adjustment based on data from the "monitoring period". The interim limit is only in effect for 90 days at which time TRP's permit modification should be complete. The Department believes that EPA has allowed the use of an adjustable limit in the past, constrained by certain parameters (such as non-steady state limits), and backed by a worst case air quality analysis (meeting the NAAQS) as a reasonable approach.

In summary, after evaluation of the previously discussed information the Department determined that the operation of OFA and FGR combustion controls and SNCR in combination with BMP, CC and implementation of the *Best Management Operating Procedures for Ash-Pulling Periods* constitutes BACT for Ash-pulling periods and is in effect until: 1) TRP verifies that they can meet steady-state NOx limits in Section II.D.14.a.i. and II.D.14.a.iii; and/or 2) TRP submits a permit modification for ash-pulling periods with proposed numerical limits for NOx, including the required BACT analysis.

If TRP verifies that steady-state limits apply, then the previously determined NOx BACT limits (under MAQP #3175-04) apply as follows during ash-pulling periods:

- 47.24 lb/hr, based on a 1-hr average; and
- After installation of SNCR, $NO_x$ emissions from the Boiler stack shall not exceed 0.196 lb/MMBtu based on a rolling 30-day average.

**$SO_2$ BACT Analysis for Ash-Pulling Periods**

**Step 1 - Identify All Control Technologies**

$SO_2$ and $SO_3$ are two sulfur oxides $SO_x$ that are formed whenever any material containing sulfur is burned. Emissions from fossil fuel combustion consist primarily of $SO_2$. Additional compounds of $SO_x$ also form at a much lower quantity and consist of $SO_3$ and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process.

The US EPA RBLC, CARB's BACT database, BAAQMD BACT Guidelines, and SCAQMD BACT Determinations were reviewed to identify the possible types of $SO_2$ controls permitted for coal/wood-fired boilers during ash-pulling periods.

Review of these databases for BACT during ash-pulling periods did not identify any control options. However, based on review of available literature, and without regard to feasibility, TRP evaluated the following control options for $SO_2$ emissions from the boiler during ash-pulling periods:

- Coal Specifications;
- Modification to Boiler;
- Best Management Practices;
- FGD;
- Wet scrubbers; and
- Spray dry absorption;

FGD and coal specifications are already being used by TRP to control emissions from the boiler. TRP believes that ash-pulling events will be considered steady-state operation. Because the Department has already analyzed most of these technologies and determined which control options constitute BACT for $SO_2$ during non-steady state operations, no further analysis is required for these control options. Therefore, the Department did not re-evaluate: Flue Gas Desulfurization, Wet Scrubbers, or Spray dry Absorption. These options were evaluated under MAQP #3175-04 for steady-state operations and further analysis is not necessary.

In addition to the control technologies, work practices, and best management practices that have already been selected as BACT under this permit action and MAQP #3175-04, TRP evaluated the following additional methods to control $SO_2$:

Coal Specifications

With any wood/coal fired steam co-generation plant, the properties of fuel varies and the choice of fuels utilized directly impacts the amount of $SO_2$ emissions. In general, low-sulfur coal reduces the sulfur fed to the boiler and is generally a highly effective way to reduce $SO_2$ because approximately 95% of the fuel sulfur is converted to $SO_2$ during combustion; the remainder is typically bound in the ash.

TRP uses subbituminous coal with low sulfur content. Bituminous coals from mines in the eastern and midwestern U.S. generally have a higher heating value, but also have significantly higher sulfur content. Regionally available coals (i.e., from Montana, Wyoming, and North Dakota) contain sulfur in the range of 0.3% to over 3% by weight.

TRP anticipates that the boiler will meet steady-state $SO_2$ emission limits that were established as BACT in MAQP #3175-04. TRP estimates the average sulfur content of coal burned at approximately 0.7% by weight and the typical heat content of coal burned at TRP varies from approximately 10,000 to 10,500 Btu per pound on an as-received basis. The table below provides a summary of coal parameters that were used in this BACT analysis.

**Table IX. Coal Specifications.**

| COAL PARAMETER | PERMIT LIMITS | TYPICAL COAL |
|---|---|---|
| **Heat content (Btu/lb)** | **≥ 8,000** | **10,200** |
| **Sulfur content (lbs S/MMBtu)** | **≤ 0.745** | **≤ 0.745** |

TRP proposes to use low sulfur coal during ash-pulling events and anticipates that all of the coal received will have a sulfur content less than or equal to 0.745 lbs S/MMBtu. TRP proposes to balance the heat content and/or the sulfur content (by weight) in order to maintain the sulfur content at less than 0.745 lb S/MMBtu at all times. For instance, if the heat content of coal is 10,200 Btu/lb then the sulfur content (by % weight) will not exceed 0.76. However, if the heat content of coal is 8,000 Btu/lb the sulfur content (by % weight) will not exceed 0.6. Both scenarios result in a sulfur content of 0.745 lb S/MMBtu.

Boiler Modification
Because ash-pulling periods are required for proper operation of the TRP boiler, TRP evaluated several options to assist with combustion control, such as: modification to the boiler, duration and frequency of these events, and a guidance document outlining a systematic approach to ash-pulling events for operators (see Attachment 4).

*Boiler Modification*: The boiler modification adds small ports (equipped with caps) for inspection and to allow the manual use of a rod to break up large bottom ash clinkers and move clinker to the discharge position for the grinder. This approach limits the amount of excess air introduced to the boiler and precludes the operator from opening the doors to rod the clinker and limits disruption to the boiler.

*Duration and Frequency:* Modification to the boiler in addition to the best management practices should decrease the duration of the ash-pulling events. TRP has proposed 1-hour ash pulling events twice per day rather than 2-hours twice per day.

Best Management Practices (BMP)

TRP proposes to implement *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department (and outlined in Attachment 4) to minimize emissions. The fundamental basis of the BMP is to minimize the amount of time during which either or both of the two sliding doors are opened to allow manual raking of the bottom ash from the boiler bottom ash hopper into the top-loading inlet of the clinker grinders. The doors are closed as soon as the measure volume of the ash has been raked to fill the top of the clinker grinder.

TRP has indicated that approximately three to four of these cycles are required during an ash-pulling period and anticipates that this will take no longer than one hour. TRP has outlined the ash-pulling process which allows the operation a systematic approach to ash-pulling and intends to evaluate urea injection for optimal injection time as well as potentially increasing the rate of injection during this time period.

**Step 2 – Technical Feasibility Analysis**

TRP anticipates two ash-pulling periods per day and the duration of these events is estimated at approximately 30-60 minutes. The remaining control technologies were evaluated for ash-pulling periods.

**Table X. Rank of Remaining Control Technologies.**

| Control Technology | Technically Available | Technically Feasible |
|---|---|---|
| Coal Specifications | Yes | Yes |
| BMP | Yes | Yes |
| CC | Yes | Yes |

**Step 3 – Rank Remaining Options by Control Effectiveness**

**Table XI. Rank by Control Effectiveness.**

| Rank | Control Technology |
|---|---|
| 1 | Coal Specifications |
| 2 | BMP |
| 3 | CC |

**Step 4 – Evaluate Most effective Controls and Document Results**

TRP proposes to implement all of the items discussed for CC and BMPs. In addition, TRP has proposed to use coal that meets the $\leq$ 0.745 lbs S/MMBtu limit at all times. Because all other options were eliminated or were selected as BACT for steady-state operations, and TRP has adopted the remaining control options for ash-pulling periods, no further analysis is necessary

**Step 5 – Select BACT**

Under the current permit action, TRP proposed and the Department concurred that the implementation of all of the items discussed for CC and BMPs. In addition, TRP has proposed to use coal that meets the ≤ 0.745 lbs S/MMBtu limit at all times constitutes BACT for the control of $SO_2$ emissions from the boiler during ash-pulling events. The Department determined (under MAQP # 3175-04) that installation and operation of an FGD system with an emission rate of 0.220 lb/MMBtu based on a 30-day rolling average constitutes BACT. The Department believes a 30-day rolling average is necessary because the effectiveness of control equipment is highly dependent on specific boiler operating characteristics, control equipment operating parameters, and the $SO_2$ emissions from the boiler stack will vary during ash-pulling events.

With the modifications to the boiler and operating procedures, TRP believes they can meet steady-state emission limits for $SO_2$ during ash-pulling periods, but does not have an emission data to base this on.

Therefore, TRP has proposed a 60-day "monitoring period" following commencement of commercial operation to collect data during ash-pulling periods according to the *Monitoring Plan to Determine Emission Limits During Ash-Pulling Periods* on file with the Department in order to verify $SO_2$ emissions. Under this permit action, the Department required that TRP collect 30-days of certified $SO_2$ CEMs data. TRP has the ability to collect up to 180 days of certified $SO_2$ data for ash-pulling periods, but the data collection must be completed within 180 day of commencement of commercial operations or initial boiler startup. In an effort to limit the amount of additional time for monitoring during ash-pulling periods, the Department concluded that the data must be collected by a certified monitor and must be acquired within 180 days of initial startup of the boiler or commencement of commercial operations following issuance of MAQP #3175-06.

The data gathered during the monitoring period shall be reported as outlined in Attachment 5 and must be submitted to the Department at least 15-days following completion of the monitoring period, but no later than 195 days following commencement of commercial operation or initial startup of the boiler following issuance of MAQP #3175-06. TRP's report to the Department shall include: 1) verification that TRP can meet steady-state $SO_2$ limits outlined in Section II.14.c.i. and 14.c.ii or 2) a permit modification to establish permit limits during ash-pulling periods.

In any event, TRP must proceed with ash-pulling in a manner that minimizes $SO_2$ emissions by implementing BMP and CC, by modifying the boiler to add inspection ports for "rodding", and by following good combustion control in accordance with *Best Management Operating Procedures for Ash-Pulling Periods* on file with the Department (and outlined in Attachment 4). The Department has determined burning coal that meets the ≤ 0.745 lb S/MMBtu limit and initiating good CCs and BMPs constitutes BACT until such time that $SO_2$ limits can either be verified or established under a permit modification.

In the event that TRP is unable to meet steady-state limits and is required to submit a permit modification for ash-pulling periods, TRP will be subject to a temporary BACT limit established for non-steady state operations (startup and shutdown limits). This temporary BACT limit is subject to adjustment based on data from the "monitoring period". The interim limit is only in effect for 90 days at which time TRP's permit modification should be complete. The Department believes that EPA has allowed the use of an adjustable limit in the past, constrained by certain parameters (such as non-steady state limits), and backed by a worst case air quality analysis (meeting the NAAQS) as a reasonable approach.

In summary, after evaluation of the previously discussed information the Department has determined burning coal that meets the ≤ 0.745 lb S/MMBtu limit and initiating good CCs and BMPs constitutes

BACT until such time that $SO_2$ limits can either be verified or established under a permit modification of the *Best Management Operating Procedures for Ash-Pulling Periods* constitutes BACT for Ash-pulling periods and is in effect until: 1) TRP verifies that they can meet steady-state $SO_2$ limits in Section II.D.14.c; and/or 2) TRP submits a permit modification for ash-pulling periods with proposed numerical limits for $SO_2$ including the required BACT analysis.

If TRP verifies that steady-state limits apply, then the previously determined $SO_2$ BACT limits (under MAQP #3175-04) also apply as follows during ash-pulling periods:

- 0.220 lb/MMBtu, based on a rolling 30-day average; and
- 72.3 lb/hr, based on a 1-hr average.

## IV. Emission Inventory

| Source | PM | $PM_{10}$ | $NO_x$ | CO | $SO_x$ | VOC | Pb | HCl |
|---|---|---|---|---|---|---|---|---|
| Babcock & Wilcox boiler (192.8 MMBtu/hr) | 0.00 | 0.00 | 165.52 | 218.72 | 185.78 | 26.18 | 0.04 | 9.50 |
| Boiler Baghouse DC5 (70,000 acfm) | 25.86 | 25.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fuel Handling Baghouse DC1 (2,200 acfm) | 1.65 | 1.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fuel Handling Baghouse DC2 (1000 acfm) | 0.75 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Lime Silo Baghouse DC3 (1000 acfm) | 0.75 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Fly Ash Silo Baghouse DC4 (1000 acfm) | 0.75 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Bottom Ash Silo Baghouse DC6 (1000 acfm) | 0.75 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Vehicle Traffic | 5.35 | 2.41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Cooling Tower | 3.01 | 3.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Outdoor Coal Storage Operations | 0.96 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Outdoor Wood-Waste Storage Operations | 0.48 | 0.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Disturbed Areas (Berm) | 0.22 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total Emissions** | 40.54 | 37.47 | 165.52 | 218.72 | 185.78 | 26.18 | 0.04 | 9.50 |

A complete emission inventory for this facility is on file with the Department. The emissions for non-steady state operation and ash pulling events with respect to NOx and $SO_2$ emissions were not included in the summary table above, but are detailed below.

***Boiler***

Heat Input Capacity: 192.8 MMBtu/hr
Normal Operating Hours: 8760 hr/yr

**Startup and Shutdown Emission Calculations**

Startup $NO_x$ Emission Calculation
Emission Factor: 74.0 lb/hr (BACT Limit)
Emission Calculation: 74.0 lb/hr * 48 hrs/startup * 4 startups/year * 0.0005 ton/lb = 7.10 ton/yr

Shutdown NOx Emission Calculation
Emission Factor: 74.0 lb/hr (BACT Limit)
Emission calculation: 74.0 lb/hr * 8 hrs/shutdown * 4 shutdowns/year * 0.0005 ton/lb = 1.18 ton/yr

Total NOx: 7.1 tpy + 1.18 tpy = **8.28 tpy**

Startup $SO_2$ Emission Calculation
Emission Factor: 155.0 lb/hr (BACT Limit)
Emission Calculation: 155.0 lb/hr * 48 hrs/startup * 4 startups/year * 0.0005 ton/lb = 14.9 ton/yr

Shutdown $SO_2$ Emission Calculation
Emission Factor: 155.0 lb/hr (BACT Limit)
Emission calculation: 155.0 lb/hr * 8 hrs/shutdown * 4 shutdowns/year * 0.0005 ton/lb = 2.48 ton/yr

Total $SO_2$: 14.9 tpy + 2.48 tpy = **17.38 tpy**

**Ash-pulling Emission Calculations**

$NO_x$ Emission Calculation
Emission Factor: 47.24 lb/hr (BACT Limit)
Emission calculation: 47.24 lb/hr * 2 hrs ash-pulling/day * 365 days/year * 0.0005 ton/lb = 17.24 ton/yr

$NO_x$ Emission Calculation
Emission Factor: 0.196 lb/MMBtu (BACT Limit)
Emission calculation: 0.196 lb/MMBtu * 192.8 MMBtu/hr *2 hours/day * 365 days/year * 0.0005 ton/lb = 13.79 ton/yr

$SO_2$ Emission Calculation
Emission Factor: 72.3 lb/hr (BACT Limit)
Emission calculation: 72.3 lb/hr * 2 hrs ash-pulling/day * 365 days/year * 0.0005 ton/lb = 26.4 ton/yr

$SO_2$ Emission Calculation (30-day average)
Emission Factor: 0.220 lb/MMBtu (BACT Limit)
Emission calculation: 0.220 lb/MMBtu * 192.8 MMBtu/hr *2 hours/day * 365 days/year * 0.0005 tos/lb = 15.48 ton/yr

## V. Existing Air Quality

The air quality classification for the immediate area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for all pollutants. The closest nonattainment area is the Thompson Falls $PM_{10}$ nonattainment area. The boundary is approximately 3.7 miles (6 kilometers (km)) from the proposed facility. Previous ISC3 computer modeling conducted for the permitted project demonstrates that operation of the facility will not adversely impact the Thompson Falls $PM_{10}$ nonattainment area. The current permit action does not result in any increase to allowable or actual $PM_{10}$ emissions from the source; therefore, the current permit action will not result in further impacts to the affected non-attainment area.

## VI. Ambient Air Impact Analysis

Based on past modeling, the Department has determined that TRP operating in compliance with MAQP #3175-06 is expected to maintain compliance with all applicable standards. Modeling has also shown that the project is not expected to adversely impact the Thompson Falls $PM_{10}$ non-attainment area.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

| YES | NO | |
|---|---|---|
| X | | 1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights? |
| | X | 2. Does the action result in either a permanent or indefinite physical occupation of private property? |
| | X | 3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property) |
| | X | 4. Does the action deprive the owner of all economically viable uses of the property? |
| | X | 5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)]. |
| | | 5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests? |
| | | 5b. Is the government requirement roughly proportional to the impact of the proposed use of the property? |
| | X | 6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action) |
| | X | 7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally? |
| | X | 7a. Is the impact of government action direct, peculiar, and significant? |
| | X | 7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded? |
| | X | 7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question? |
| | X | Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas) |

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

**DEPARTMENT OF ENVIRONMENTAL QUALITY**
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

# FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Thompson River Power, LLC (TRP)
701 E. Lake St., Suite 300
Wayzata, MN 55391

Montana Air Quality Permit Number: 3175-06

Preliminary Determination Issued: December 19, 2008
Department's Decision Issued: January 23, 2009
Permit Final: February 10, 2009

1. *Legal Description of Site*: The TRP facility is located in Section 13, Township 21 North, Range 29 West, Sanders County, Montana.

2. *Description of Project*: On April 22, 2008, the Board remanded MAQP #3175-04 to the Department to conduct a thorough, top-down supplemental BACT analysis for periods of non-steady state operation. The current permit action is a modification to MAQP #3175-04 pursuant to the Order issued by the Board in the matter of contested case number BER 2006-18 AQ. The modification establishes permit limitations, conditions and reporting requirements in accordance with the results of the startup, shutdown and ash-pulling periods top-down BACT determination submitted by TRP on May 30$^{th}$ with additional information received on July 29th, August 21$^{st}$, September 3$^{rd}$, October 2$^{nd}$, October 21$^{st}$, and October 29$^{th}$ and November 10$^{th}$ pursuant to the Board order.

   Pursuant to this request, TRP requested the following changes to the permit terms/conditions relating to Startup and Shutdown Events and Ash-Pulling Periods. In addition to the requested permit modification, the current permit action also includes revisions to assure compliance during non-steady state operations and ash-pulling periods.

   - Incorporation of *Best Management Operational Practices for Startup and Shutdown Events*
   - Evaluation of Best Available Control Technology (BACT) specifically for Startup and Shutdown Events;
   - Evaluation of BACT specifically for Ash-Pulling Periods;
   - Establishment of a federally enforceable boiler heat sulfur limit;
   - Establishment of $NO_x$ and $SO_2$ limits for Startup and Shutdown Events and Ash-Pulling Periods;
   - Inclusion of a "monitoring period" to establish $NO_x$ and $SO_2$ emission limits, and/or to verify existing steady-state limits during Ash-Pulling Periods; and
   - Incorporation of *Best Management Operating Procedures for Ash-Pulling Periods.*

   A more detailed analysis of the Department's action would be contained in Section I.D of the permit analysis to this permit.

3. *Objectives of Project*: The purpose of the current permit action would be to respond to the Boards permit remand, specifically to allow for proposed changes in applicable emission limits, and facility operations, as demonstrated is appropriate under BACT.

4. *Description of Alternatives*: The Department could deny issuance of the modified air quality permit under the remand, or the "no action" alternative which would be to not act on the remand, neither of which would be appropriate responses to the Board order.

5. *A Listing of Mitigation, Stipulations and Other Controls*: A list of enforceable conditions and a BACT analysis would be contained in Permit #3175-06.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action alternative" was discussed previously.

| | | Major | Moderate | Minor | None | Unknown | Comments Included |
|---|---|---|---|---|---|---|---|
| A | Terrestrial and Aquatic Life and Habitats | | | X | | | Yes |
| B | Water Quality, Quantity, and Distribution | | | X | | | Yes |
| C | Geology and Soil Quality, Stability and Moisture | | | X | | | Yes |
| D | Vegetation Cover, Quantity, and Quality | | | X | | | Yes |
| E | Aesthetics | | | X | | | Yes |
| F | Air Quality | | | X | | | Yes |
| G | Unique Endangered, Fragile, or Limited Environmental Resources | | | X | | | Yes |
| H | Demands on Environmental Resource of Water, Air and Energy | | | X | | | Yes |
| I | Historical and Archaeological Sites | | | X | | | Yes |
| J | Cumulative and Secondary Impacts | | | X | | | Yes |

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

Any impacts resulting from the proposed project to terrestrial and aquatic life and habitats would be minor because all proposed activities would take place within the defined TRP property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

Terrestrials (such as deer, antelope, rodents, and insects) would use the general area of the facility. The area around the facility would be fenced to limit access to the facility. The fencing would likely not restrict access from all animals that frequent the area, but it may discourage some animals from entering the facility property. Further, because other industrial sources, including the Thompson River Lumber Company (TRL) and a solid waste disposal facility are located directly adjacent to the proposed TRP property boundary, terrestrials that routinely inhabit the area are accustomed to the industrial character of the site. Therefore, any impacts to terrestrial and aquatic life and habits due to the proposed modified operation with respect to startup and shutdown and ash-pulling practices of the TRP facility would have minor and typical impacts.

B. Water Quality, Quantity, and Distribution

Any impacts resulting from the proposed project to water quality, quantity, and distribution would be minor because all proposed activities would take place within the defined TRP property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

Overall, any impacts to water quality, quantity, and distribution from TRPs proposed permit modifications, with respect to startup, shutdown, ash-pulling practices resulting in air emissions and deposition of air emissions would be minor.

C. Geology and Soil Quality, Stability, and Moisture

Any impacts resulting from the proposed project to geology and soil quality, stability, and moisture would be minor because all proposed activities with respect to limits and practices associated with limiting emissions during startup, shutdown, and ash pulling periods/events would take place within the defined TRP property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

D. Vegetation Cover, Quantity, and Quality

Any impacts resulting from the proposed project to vegetation cover, quantity, and quality would be minor because all proposed activities with respect to limits and practices associated with limiting emissions during startup, shutdown, and ash pulling periods/events would take place within the defined TRP property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

E. Aesthetics

Minor impacts to the aesthetic nature of the area would result from the proposed TRP modification because all proposed activities with respect to limits and practices associated with limiting emissions during startup, shutdown, and ash pulling periods/events would take place within the defined TRP property boundary, an existing industrial site. Any changes in operational practices to minimize those emissions may be visible from locations around the TRP site. However, the TRP site is a previously disturbed industrial location with a solid waste transfer station and lumber sawmill in relatively close proximity, any aesthetic impacts would be minor and consistent with current industrial land use of the area.

The facility is visible from MT Highway 200 (approximately ¼ mile to the north), a small residential subdivision (approximately ¾ mile west/southwest), an individual residence (approximately ½ mile west), and may be visible from the Clark Fork River (approximately ¼ mile south and located in the river valley below the proposed site). Overall, any impacts to the aesthetic nature of the project area from TRPs proposed permit modifications, including construction activities and normal operations resulting in air emissions and deposition of air emissions would be minor.

F. Air Quality

The air quality impacts from the current permit action would be minor because Permit #3175-06 would include conditions limiting emissions of air pollution from the source, specifically by minimizing emissions associated with startup, shutdown, and ash pulling periods/events.

In addition, the Department determined, based on the ambient air quality dispersion modeling analysis conducted for MAQP #3175-04, that the operation of the TRP under the conditions associated with MAQP #3175-06 would not cause or contribute to a violation of any ambient air quality standard. The Clean Air Act, which was last amended in 1990, requires the U.S. Environmental Protection Agency (EPA) to set NAAQS for pollutants considered harmful to public health and the environment (Criteria Pollutants: carbon monoxide (CO), $NO_x$, Ozone ($O_3$), Lead (Pb), particulate matter with an aerodynamic diameter less than or equal to 10 microns ($PM_{10}$), and $SO_2$). In addition, Montana has established equally protective or, in some cases, more stringent standards for these pollutants termed Montana Ambient Air Quality Standards (MAAQS). The Clean Air Act established two types of NAAQS, Primary and Secondary. Primary Standards set limits to protect public health, including, but not limited to, the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary Standards set limits to protect public welfare, including, but not limited to, protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Primary and Secondary Standards are identical with the exception of $SO_2$ which has a less stringent Secondary Standard. The air quality classification for the immediate area of proposed TRP operation is considered "Unclassifiable or Better than National Standards" (40 CFR 81.327) for all pollutants. The closest nonattainment area is the Thompson Falls $PM_{10}$ nonattainment area located approximately 3.7 miles west/northwest of the TRP site location.

Overall, any impacts to the air quality of the project area from TRPs proposed permit modifications, including construction activities, normal operations resulting in air emissions, and deposition of air emissions would be minor and in compliance with all applicable MAAQS and NAAQS.

G. Unique Endangered, Fragile, or Limited Environmental Resources

Under the initial TRP Permit Action #3175-00, the Department contacted the Montana Natural Heritage Program (MNHP) in an effort to identify any species of special concern associated with the proposed site location. Search results concluded there are 5 such environmental resources in the area. Area in this case is defined by the township and range of the proposed site, with an additional one-mile buffer. The species of special concern identified by MNHP include the *oncorhynchus clarki lewisi* (Westslope Cutthroat Trout), *salvelinus confluentus* (Bull Trout), *felis lynx* (Lynx), *ursus arctos horribilis* (Grizzly Bear), and *clarkia rhomboidia* (Common Clarkia). While the previously cited species of special concern have been identified within the defined area, the MNHP search did not indicate any species of special concern located directly on the TRP site.

The TRP site has historically been used for industrial purposes. Any changes in operation associated with minimizing emissions associated with startup, shutdown, and ash-pulling periods/events would take place within the 6-acre plot of land leased by TRP and located within the existing 165-acre TRL mill property boundary. Because industrial operations have been ongoing within the existing TRL property boundary for an extended period of time (exceeding 50 years) and potential permitted emissions from TRP show compliance with all applicable air quality standards, it is unlikely that any of these species of special concern would be affected by the proposed project. Overall, any impacts to any unique endangered, fragile, or limited environmental resources would be minor.

H. Demands on Environmental Resource of Water, Air, and Energy

Demands on environmental resources of water, air, and energy would be minor. As previously discussed, the proposed permit modification would increase allowable air emissions of $NO_x$ and $SO_2$; however, air dispersion modeling demonstrated compliance with the MAAQS/NAAQS.

Therefore, any impacts to air resources in the area would be minor and would be in compliance with applicable standards. Any impacts to the local air resource would be minor as demonstrated through the ambient air quality impact analysis conducted for the proposed permit modification.

Regarding impacts to the environmental resource of water, this permit action does not include any increase in the demand for water. Therefore, any impacts to the demand for water resources in the affected area associated with TRP operations has already been analyzed under previous permit actions and determined to be minor.

With respect to energy, TRP would produce approximately 16.5 MW of power with a majority being sold and sent directly to the power grid and the remaining power purchased and used by TRL and TRP facility operations. This permit action would not change, in general, the overall amount of power used or produced.

Overall, any impacts to the demands on the environmental resources of water, air, and energy from TRPs proposed permit modifications would be minor.

I. Historical and Archaeological Sites

Under the initial Permit Action #3175-00, conducted in 2001, in an effort to identify any historical and archaeological sites near the proposed project area, the Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO). According to SHPO, the absence of recorded cultural/historical properties in the search locale may be due to a lack of previous inventory. Due to the potential for minor additional ground disturbance from the proposed project and the low topography of the area, the potential for the presence of historical/cultural sites that could be impacted by the project does exist. Therefore, SHPO recommended that a cultural resource inventory be conducted prior to project initiation. However, neither the Department nor SHPO has the authority to require TRP to conduct a cultural resource inventory. The Department determined that due to the previous industrial disturbance in the area (the area is an active industrial site with multiple occasions for industrial disturbance) and the small amount of land disturbance that may be required for the proposed permit modification, it is unlikely that any undisturbed existing historical or cultural resource exists in the area and if these resources did exist, any impacts would be minor due to previous industrial disturbance in the area.

J. Cumulative and Secondary Impacts

Overall, any cumulative and secondary impacts from the proposed permit modification on the physical and biological resources of the human environment in the immediate area would be minor due to the fact that the predominant use of the surrounding area would not change as a result of the proposed project. The Department believes that this facility could be expected to operate in compliance with all applicable rules and regulations as would be outlined in MAQP #3175-06.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

| | | Major | Moderate | Minor | None | Unknown | Comments Included |
|---|---|---|---|---|---|---|---|
| A | Social Structures and Mores | | | | X | | Yes |
| B | Cultural Uniqueness and Diversity | | | | X | | Yes |
| C | Local and State Tax Base and Tax Revenue | | | X | | | Yes |
| D | Agricultural or Industrial Production | | | | X | | Yes |
| E | Human Health | | | X | | | Yes |
| F | Access to and Quality of Recreational and Wilderness Activities | | | X | | | Yes |
| G | Quantity and Distribution of Employment | | | | X | | Yes |
| H | Distribution of Population | | | | X | | Yes |
| I | Demands for Government Services | | | X | | | Yes |
| J | Industrial and Commercial Activity | | | X | | | Yes |
| K | Locally Adopted Environmental Plans and Goals | | | | X | | Yes |
| L | Cumulative and Secondary Impacts | | | X | | | Yes |

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores
B. Cultural Uniqueness and Diversity

The proposed permit modification would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) or impact the cultural uniqueness and diversity of the area because the current permit action would not change the current industrial nature of the TRP operation or the overall industrial nature of the area of operation. The predominant use of the surrounding area would not change as a result of the current permit action. In addition, the overall industrial nature of the surrounding area, as a whole, would not be altered by the proposed TRP permit modification, as the area currently facilitates other industrial sources including the TRL operation and a solid waste transfer station both of which are located directly adjacent to the TRP site, as well as an existing gravel pit in the greater surrounding area.

C. Local and State Tax Base and Tax Revenue

Any impacts to the local and state tax base and tax revenue would be minor because TRP would remain responsible for all appropriate state and county taxes imposed upon the business operation. In addition, TRP employees would continue to add to the overall income base of the area.

D. Agricultural or Industrial Production

The current permit action would not displace or otherwise affect any agricultural land or practices. TRP would continue to provide power and steam for normal operations at TRL.

E. Human Health

There would be minor potential effects on human health due to minimized air emissions from startup, shutdown, and ash pulling episodes/events. In addition, Permit #3175-06 would include conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

As detailed in Section 7.F of this EA, the Clean Air Act established two types of NAAQS, Primary and Secondary. Primary Standards set limits to protect public health, including, but not limited to, the health of “sensitive” populations such as asthmatics, children, and the elderly. Under MAQP #3175-04, TRP conducted an ambient air quality impact analysis demonstrating that TRP operations, as proposed under the permit modification, would comply with all applicable ambient air quality standards thereby protecting human health. Overall, the Department determined, based on the ambient air impact analysis for previous actions in comparison to the current permit action, that any impact to public health would be minor.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed permit modifications and overall TRP operations would not affect access to any recreational or wilderness activities in the area. Following the current permit action, the TRP operation would continue to be located within the 165-acre plot that was previously used for TRL’s lumber mill operations. The area is comprised of private property with no public access and would continue in this state after modification of the permit.

G. Quantity and Distribution of Employment
H. Distribution of Population

The current permit action would result in no impacts to the quantity and distribution of employment in the area and/or the distribution of population in the area because the project would not require any additional employees.

I. Demands on Government Services

Demands on government services from the proposed permit modification would be minor because TRP would be required to procure the appropriate permits (including a state air quality permit) and any permits for the associated activities of the project. Further, compliance verification with those permits would also require minor services from the government.

As the TRP site is within an existing industrial location, employee water and sewage disposal facilities would continue to be connected to existing water and sewer sources. Further, all process water needs for the facility operations would remain unchanged as a result of the current permit action. All spent water (waste-water) would continue to be discharged to an evaporation pond to be located on site and would therefore not require the use of any county or state services, including permitting. Overall, any demands on government services resulting from the proposed permit modification would be minor.

J. Industrial and Commercial Activity

The current permit action would change various aspects of the previously permitted TRP operations, specifically related to minimizing emissions associated with startup, shutdown, and ash pulling period/events, but would not result in an overall change in facility purpose; therefore, the proposed permit modification would not impact any industrial or commercial activity in the area beyond those impacts already realized through the initial Permit Action #3175-00.

K. Locally Adopted Environmental Plans and Goals

The City of Thompson Falls is a $PM_{10}$ nonattainment area. The $PM_{10}$ nonattainment area boundary is located approximately 3.7 miles west/northwest of the TRP facility. However, the current permit action does not propose any change in allowable $PM_{10}$ emissions. Therefore, the current permit action would not contribute to the nonattainment status of the area. Because the current permit action would not allow any additional $PM_{10}$ emissions, the Department determined that the proposed permit modification would not adversely impact the local Thompson Falls $PM_{10}$ nonattainment area.

The Department is unaware of any other locally adopted Environmental plans or goals. The state air quality standards would protect air quality at the proposed site and the environment surrounding the site.

L. Cumulative and Secondary Impacts

Overall, cumulative and secondary impacts from the proposed permit modification on the economic and social resources of the human environment in the immediate area would be minor due to the fact that the predominant use of the surrounding area would not change as a result of the proposed project. The Department believes that this facility could be expected to operate in compliance with all applicable rules and regulations as would be outlined in Permit #3175-06.

*Recommendation*: An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The current permit action is for the modification of an existing and permitted electrical-steam co-generation plant. Permit #3175-06 includes conditions and limitations to ensure the facility will operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality – Water Protection Bureau.

Individuals or groups contributing to this EA: Department of Environmental Quality – Air Resources Management Bureau, Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality – Water Protection Bureau.

EA Prepared By: Jenny O'Mara.
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